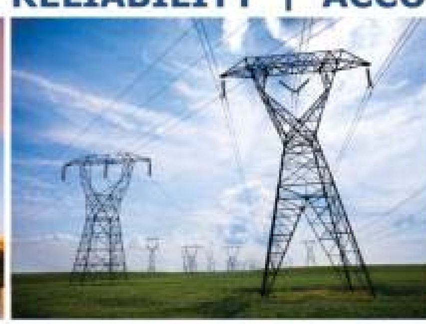
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

State of Reliability 2014

May 2014

RELIABILITY | ACCOUNTABILITY



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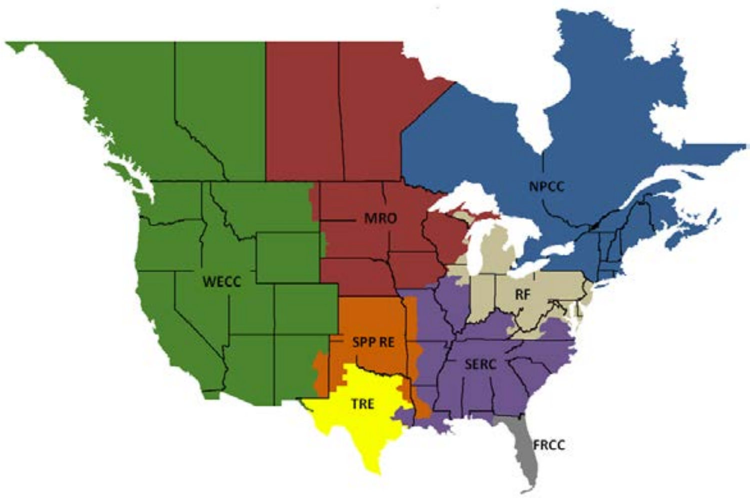
Preface

The North American Electric Reliability Corporation (NERC) prepared this assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) of North America.[1, 2]

NERC is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the BPS[3] in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

[1] H.R. 6 as approved by the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[2] The NERC Rules of Procedure, Section 800, further detail the objectives, scope, data and information requirements, and reliability assessment process requiring annual, seasonal, and long-term reliability assessments.

[3] http://www.nerc.com/files/glossary_of_terms.pdf, BPS definition, page 21.

<u>Notice</u>

This report presents metrics and trends derived from the data available at the time of publication and may be modified pending further review and analysis.

Executive Summary

The *State of Reliability 2014* report represents NERC's independent view of ongoing BPS trends to objectively provide an integrated view of reliability performance. The key findings and recommendations serve as technical input to NERC's risk assessment, Reliability Standards project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection. The analysis of BPS performance developed as part of this report provides an industry reference of historical reliability, offers analytical insights regarding industry action, and enables the identification and prioritization of specific steps that can be taken to manage risks to reliability.

Sustained High Performance for Bulk Power System Reliability

The daily severity risk index (SRI_{bps})[4] value, which measures risk impact or "stress" from events resulting in the loss of transmission, generation, and load, has been stable to improving from 2008 to 2013. Including weather-initiated events, 2013 had no high-stress days (i.e., there were no days with an SRI_{bps} greater than 5.0). On average, the SRI_{bps} was approximately as good as the performance achieved during 2008, which is the best year on record. From 2008 through 2013, the majority of high-stress days (days with high SRI_{bps} scores) were weather-initiated or weather-exacerbated; only a small number of days were associated with initiating events internal to the BPS.

The availability of the bulk transmission system remained high from 2008 to 2013. The ac transmission circuit availability remained above 97 percent, and transmission transformer availability was above 98 percent for the 2010 to 2013 period (unavailability includes both forced and planned outages). High transmission availability demonstrates that the BPS is able to perform reliably over a variety of operating conditions.

NERC continues activity on several projects to maintain the availability and resiliency of the BPS. For example, several standards projects were completed in 2013 that support sustained high performance of BPS reliability by providing the data necessary for bulk transmission system analysis: 1) the Modeling Data standards[5] provide a foundational framework for consistent data requirements and reporting procedures needed to develop planning horizon simulation models that are critical supporting the analysis of the reliability of the interconnected BPS; 2) the Demand Data standard[6] provides authority for applicable entities to collect demand, energy, and related data to support reliability studies and assessments, measuring whether there is an adequate amount of resources available to serve peak demand while also maintaining a sufficient margin to address operating events; and 3) the ATC standard[7] requires the determination of available transmission system capability and specifies that the methods and data underlying those determinations must be disclosed to those registered entities that need the information for reliability purposes.

Frequency Response Remains Stable

From 2009 to 2013, the Eastern Interconnection, ERCOT Interconnection, Québec Interconnection[8] and the Western Interconnection have shown steady frequency response performance, trending above the recommended interconnection frequency response obligation (IFRO) at all times during the study period. The Eastern Interconnection data showed a slightly downward trend in frequency response; however, this trend is not statistically significant. It is important to continue to monitor these trends to determine whether they approach or drop below the IRFO for any interconnection. The study methods and statistical results of the frequency response evaluation are summarized in Chapter 4 (ALR1-12) and detailed in Appendix B.

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[4] SRI Enhancement Whitepaper, April 9, 2014, http://www.nerc.com/comm/PC/Performance Analysis Subcommittee PAS 2013/SRI Enhancement Whitepaper.pdf
[5] Modeling Data (MOD B), http://www.nerc.com/pa/Stand/Pages/Project2010-03ModelingData(MOD-B).aspx
[6] MOD-031-1, Demand Data (MOD C), http://www.nerc.com/pa/Stand/Pages/Project2010-04DemandData(MOD-C).aspx
[7] ATC Revisions (MOD A), http://www.nerc.com/pa/Stand/Pages/Project201205MODAAvailableTransferCapability.aspx
[8] Only Québec Interconnection 2011 and 2013 frequency response data is available.

Several projects are ongoing at NERC to monitor and maintain frequency response. For example, NERC completed the development of BAL-003-1 in 2013, and FERC approved the standard on January 16, 2014. BAL-003-1 establishes a minimum frequency response obligation for each Balancing Authority (BA), provides a uniform calculation of frequency response and frequency bias settings that transition to values closer to natural frequency response, and encourages coordinated Automatic Generation Control operation. This standard, in partnership with BAL-001-2, maintains interconnection steady-state frequency within defined limits by balancing real power demand and supply in real time, ensuring that BAs take actions to maintain interconnection frequency and that they each contribute their fair share to frequency control. NERC also completed development of BAL-001-2 in 2013, which is pending regulatory approval.

RECOMMENDATION:
EXAMINE INCIDENTS IN 2013 WHERE FREQUENCY RESPONSE WAS LESS THAN IFRO. DETERMINE ACTIONS TO MAINTAIN AND IMPROVE FREQUENCY RESPONSE PERFORMANCE.

Protection System Misoperations Cause Transmission Events

Similar to the key finding in the *State of Reliability 2013* report, protection system misoperations continued to be a significant contributor to automatic transmission outage severity in 2013, as shown in Chapter 3. On average, transmission system events with protection system misoperations were more impactful than other transmission events. They were also, in aggregate, a significant contributor to transmission outage severity, indicating that a reduction in protection system misoperations would lead to an improvement in system reliability.

Protection system misoperations continues to be an area of NERC concentration. The Reliability Issues Steering Committee (RISC) has identified system protection reliability, uncoordinated protection systems, and protection system misoperations as top-priority risks to reliability. NERC has focused its Reliability Standards efforts in these areas, with the completion of the relay loadability standards[9] and continued work on relay misoperations[10] and coordination.[11] In addition, NERC staff is coordinating with the North American Transmission Forum to find ways to reduce protection system misoperations and develop ways to minimize their impact. NERC's Event Analysis activities continue to examine system events to identify actions needed to address protection system trends and common causes of misoperations.

RECOMMENDATION:
COMPLETE DEVELOPMENT OF PRC-004-3. DEVELOP ACTIONS TO ADDRESS THE THREE MOST COMMON CAUSES OF PROTECTION SYSTEM MISOPERATIONS.

Substation Equipment Failures Impact Transmission Event Severity

AC substation equipment failures can exacerbate the severity of transmission outages, as observed in the *State of Reliability 2013* report.

As recommended in the *State of Reliability 2013* report, NERC (through joint action of the Planning Committee and Operating Committee) formed the AC Substation Equipment Task Force (ACSETF) in 2013 to address ac substation equipment failures. The ACSETF has gathered ac substation equipment failure data from multiple sources, including but not limited to the Event Analysis Program, the Transmission Availability Data System (TADS), a supplemental TADS survey conducted by the ACSETF, and the WECC trouble report dataset. The data is being analyzed, and a report will be completed by the end of 2014.

[9] Generator Relay Loadability and Transmission Relay Loadability, http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx
[10] Protection System (Misoperations), http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx
[11] Protection System Coordination, http://www.nerc.com/pa/Stand/Pages/Project-2007-06-System-Protection-Coordination.aspx

In addition, NERC is focusing on increasing awareness of this risk to reliability. For example, NERC developed the adequate level of reliability metric, ALR6-13 AC Transmission Outages Initiated by Failed AC Substation Equipment, to measure performance changes in failed ac substation equipment. The metric shows that outages per element demonstrate year-over-year improvement from 2011 to 2013; this is posted on NERC's website.[12]

RECOMMENDATION:
ASSESS THE EFFECTIVENESS OF NERC ADVISORY ADDRESSING 345 KV SF_6 BREAKER FAILURES. DEVELOP A PLAN TO ADDRESS THE CAUSES OF SUBSTATION EQUIPMENT FAILURES.

NERC's analysis of substation equipment, specifically circuit breakers, identified a failure trend for a specific type of circuit breaker in many of the reported events. A case history was established for a specific type of 345 kV SF_6 puffer-type circuit breaker failure. The average time between reported failures of these breakers was 4.2 months for the six failures discovered in the NERC Event Analysis program. NERC further uncovered a maintenance advisory published for this equipment that indicated the need for equipment modification. These analyses resulted in NERC issuing a Level 1 Advisory Alert regarding identification of a trend in 345 kV SF_6 puffer-type circuit breaker failures and the potential risk it posed to reliability. The purpose of the alert was to ensure industry was aware of the recent failures and previously published maintenance advisories, so appropriate action could be taken by entities that have this particular equipment. Since the alert was published, there have been no reported events caused by this failure mechanism.

Use of Energy Emergency Alert Level 3 Declines

In 2013 there were seven Energy Emergency Alert (EEA) Level 3[13] events declared, which is significantly less than the number that occurred in prior years. EEA trends provide a relative indication of performance measured at a BA or interconnection level. By definition, when an EEA Level 3 Alert is issued, firm-load interruptions are imminent or in progress. An EEA Level 3 Alert indicates an issue with the real-time adequacy of the electric supply system. It may be due to a lack of fuel or dependence on transmission for imports into a constrained area, not simply a lack of available generation resources. In 2013, NERC began to collect and analyze more information surrounding EEA Level 3 events, including load shed, if any. Only one of the seven EEA 3 events in 2013 required firm load to be shed to preserve reliability of the BPS. This further demonstrates the ability of the BPS to perform well under stressed conditions.

RECOMMENDATION:
ANALYZE SYSTEM EVENTS THAT RESULTED IN FIRM LOAD SHEDDING TO DETERMINE ANY COMMON CAUSES OR TRENDS

There were eight instances of load shedding to mitigate actual and post-contingency transmission system conditions in 2013. The total amount of load shed did not exceed 300 MW in any of these events, and all but one lasted less than four hours.

NERC Continues to Focus on Risks to Reliability

The goal of the *State of Reliability 2014* report is to quantify risk and performance, highlight areas for improvement, and reinforce and measure success in controlling these risks. A number of activities are in place to further these objectives.

The RISC was formed in 2011 and continues to identify top-priority risks to reliability. The ongoing work in NERC's Performance Analysis area provides a foundation for their risk assessments. These highest-priority risks are being packaged into specific project work aimed at addressing components of reliability risk. NERC is actively addressing many of these risks, as called for in its corporate goals*: Review the BES[14] risk profile each year to determine actual and potential risks. The target is to identify, select, and mitigate the high-priority risks.*

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[12] Reliability Indicators: Automatic Outages Initiated by Failed AC Substation Equipment / Automatic Outages Initiated by Failed AC Circuit Equipment, http://www.nerc.com/pa/RAPA/ri/Pages/Automatic-OutagesInitiatedbyFailedACSubstationACCirc.aspx

[13] http://www.nerc.com/pa/rrm/ea/Documents/EOP-002-2.pdf, EEA3 definition, page 9

[14] http://www.nerc.com/files/glossary_of_terms.pdf, BES Definition, page 20

For example, in 2014, the following projects are now ongoing:

- Changing Resource Mix
- Extreme Physical Events
- Protection System Misoperations
- Cold Weather Preparedness
- Right-of-Way Clearances
- 345 kV Breaker Failures

The NERC Standards department continues to review standards to improve the performance of the BPS.[15] This work focuses on improving the quality and content of standards while addressing key system risks identified by analyzing existing trends.

NERC continues to develop solutions to evolving threats to reliability. The BPS is a highly interconnected system with some remaining challenges, including weather (e.g., droughts, floods, severe winter) and the potential for major cyber and physical attacks. Under the direction of the Critical Infrastructure Protection Committee (CIPC), the Performance Analysis Subcommittee[16] (PAS) is collaborating with the Bulk Electric System Security Metrics Working Group to develop security performance metrics.

Development of Reliability Standards is also ongoing. On November 22, 2013, FERC approved the CIP Version 5 standards, which offer several improvements over previous versions, including increased flexibility in implementing risk mitigation to individual entity operations, elimination of unnecessary documentation requirements, and transitions from the "in or out" classification of critical assets to a "Low-Medium-High" impact-based classification at the system level. The set of CIP Version 5 standards are currently being revised to address FERC directives issued in the order approving the standards.[17]

A physical security standard is being developed in response to a FERC order issued on March 7, 2014, which stated "…the Commission directs the ERO to develop and file for approval proposed Reliability Standards that address threats and vulnerabilities to the physical security of critical facilities on the Bulk-Power System. Such Reliability Standards will enhance the Commission's ability to assure the public that critical facilities are reasonably protected against physical attacks." The FERC order directed NERC to develop the standard in 90 days. The proposed Reliability Standard would require owners or operators of the BPS, as appropriate, to identify facilities on the BPS that are critical to the reliable operation of the BPS and then develop, validate, and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities.

NERC continues to examine impacts on the BPS related to the changing resource mix. Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the BPS will require significant changes to traditional methods used for system planning and operation. The amount of variable generation is expected to grow considerably as policy and regulations on greenhouse gas emissions are being developed and implemented by federal authorities and individual states and provinces throughout North America. Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS reliability. Operators will require new tools and practices, including potential enhancements to NERC Reliability Standards or guidelines to maintain BPS reliability. NERC is defining essential reliability services and possible sources for those services and expects to form a task force to continue related work.

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[15] NERC Reliability Standards Development Plan, http://www.nerc.com/pa/Stand/Pages/ReliabilityStandardsDevelopmentPlan.aspx

[16] Performance Analysis Subcommittee (PAS) http://www.nerc.com/comm/PC/Pages/Performance-Analysis-Subcommittee-(PAS)-2013.aspx

[17] http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx

Report Organization

Chapter 1 outlines key findings and conclusions, and Chapter 2 details the SRI$_{bps}$ trend analysis. Chapter 3 presents a framework and statistical analysis studies that identify the top risks to the BPS using transmission outage data. Chapter 4 provides an assessment for a set of adequate level of reliability metrics. Chapter 5 outlines NERC Event Analysis efforts and findings. Chapter 6 highlights the NERC Spare Equipment Database program, an emerging NERC program that provides an important tool for industry participants to use when sharing information on the availability of spare equipment.

This report was prepared by NERC staff and the NERC PAS under the direction of the Operating Committee and Planning Committees, in collaboration with many stakeholder groups,[18] including:

- Operating Committee (OC):
  - Resources Subcommittee (RS)
  - Frequency Working Group (FWG)
  - Event Analysis Subcommittee (EAS)
  - Operating Reliability Subcommittee (ORS)
- Planning Committee (PC)
  - Reliability Assessment Subcommittee (RAS)
  - System Protection and Control Subcommittee (SPCS)
  - Protection System Misoperations Task Force (PSMTF)
  - Transmission Availability Data System Working Group (TADSWG)
  - Generating Availability Data System Working Group (GADSWG)
  - Demand Response Availability Data System Working Group (DADSWG)
  - Spare Equipment Database Working Group (SEDWG)
- Compliance and Certification Committee (CCC)

Since the initial 2010 annual reliability metrics report,[19] the PAS (formerly the Reliability Metrics Working Group)[20] has enhanced data collection and trend analysis for 16 reliability indicators[21] through NERC's voluntary or mandatory data requests.

[18] NERC Committees, http://www.nerc.com/comm/Pages/default.aspx
[19] 2010 Annual Report on Bulk Power System Reliability Metrics, June 2010, http://www.nerc.com/docs/pc/rmwg/RMWG_AnnualReport6.1.pdf
[20] Reliability Metrics Working Group (RMWG), http://www.nerc.com/comm/PC/Pages/Performance Analysis Subcommittee (PAS)/Reliability-Metrics-Working-Group-RMWG-Archives.aspx
[21] Reliability Performance Metric, http://www.nerc.com/pa/RAPA/Pages/ReliabilityIndicators.aspx

Chapter 1 – Key Findings and Conclusions

2014 State of Reliability

The BPS remains reliable and performance is high, as reflected in metrics analysis provided in Chapter 4. The revised SRI_{bps}[22] and 16 metrics that measure system characteristics and performance indicate that the BPS maintained acceptable reliability performance during observed system conditions in 2013. The system is defined as having an adequate level of reliability when the following performance objectives are maintained or achieved:[23]

1. The BES does not experience instability, uncontrolled separation, cascading, or voltage collapse under normal operating conditions and when subject to predefined disturbances.
2. BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
3. BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
4. Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple contingences, unplanned and uncontrolled equipment outages, cybersecurity events, and malicious acts) are managed.
5. Restoration of the BES after major system disturbances that result in blackouts and widespread outages is performed in a coordinated and controlled manner.
6. BES transmission capability is assessed to determine the availability to meet anticipated BES demands during normal operating conditions and when subject to predefined disturbances.
7. Resource capability is assessed to determine the BES's availability to meet anticipated BES demands during normal operating conditions and when subject to predefined disturbances.

2013 Overall Reliability Performance

An adequate level of reliability was preserved in 2013 as performance remained high, as evidenced by no significant upward or downward trends in the metrics for the 2008 to 2013 period. The SRI_{bps} and 16 metrics that measure the characteristics of an adequate level of reliability indicate the BPS is within the defined acceptable ALR performance objectives. Based on the data and analysis in the latter chapters of this report, the following key findings were identified:

- Sustained high performance for BPS reliability
- Frequency response remains stable
- Protection system misoperations cause transmission events
- Substation equipment failures impact transmission event severity
- Use of Energy Emergency Alert Level 3 declined

[22] SRI_{bps} is a "stress" index, measuring risk impact from events resulting in transmission loss, generation loss, and load loss.

[23] Definition of "Adequate Level of Reliability," http://www.nerc.com/comm/Other/Adequate Level of Reliability Task Force ALRTF DL/Final Documents Posted for Stakeholders and Board of Trustee Review/10_04_12_ALR_Definition_clean.pdf

Key Finding 1: Sustained High Performance for Bulk Power System Reliability

Daily Performance Severity Risk Assessment

Based on the SRI_{bps} and 16 metrics that measure the characteristics of an ALR, BPS reliability is adequate and within the defined acceptable ALR performance objectives. Seven out of the top-10 most severe events in 2013 were initiated or exacerbated by weather. There were no high-stress days (i.e., there were no days with an SRI_{bps} greater than 5.0) in 2013, compared to three days in 2012.

Figure 1.1 captures the daily SRI_{bps} value from 2008 to 2013, including the historic significant events. The SRI_{bps} is a daily, blended metric where transmission loss, generation loss, and load loss events are aggregated into a single value that represents the performance of the system. Accumulated over one year, these daily performance measurements are sorted in descending order to evaluate the year-on-year performance of the system. Since there is a significant difference between best days, normal days, and high-stress days in terms of SRI values, the curve is depicted using a logarithmic scale.

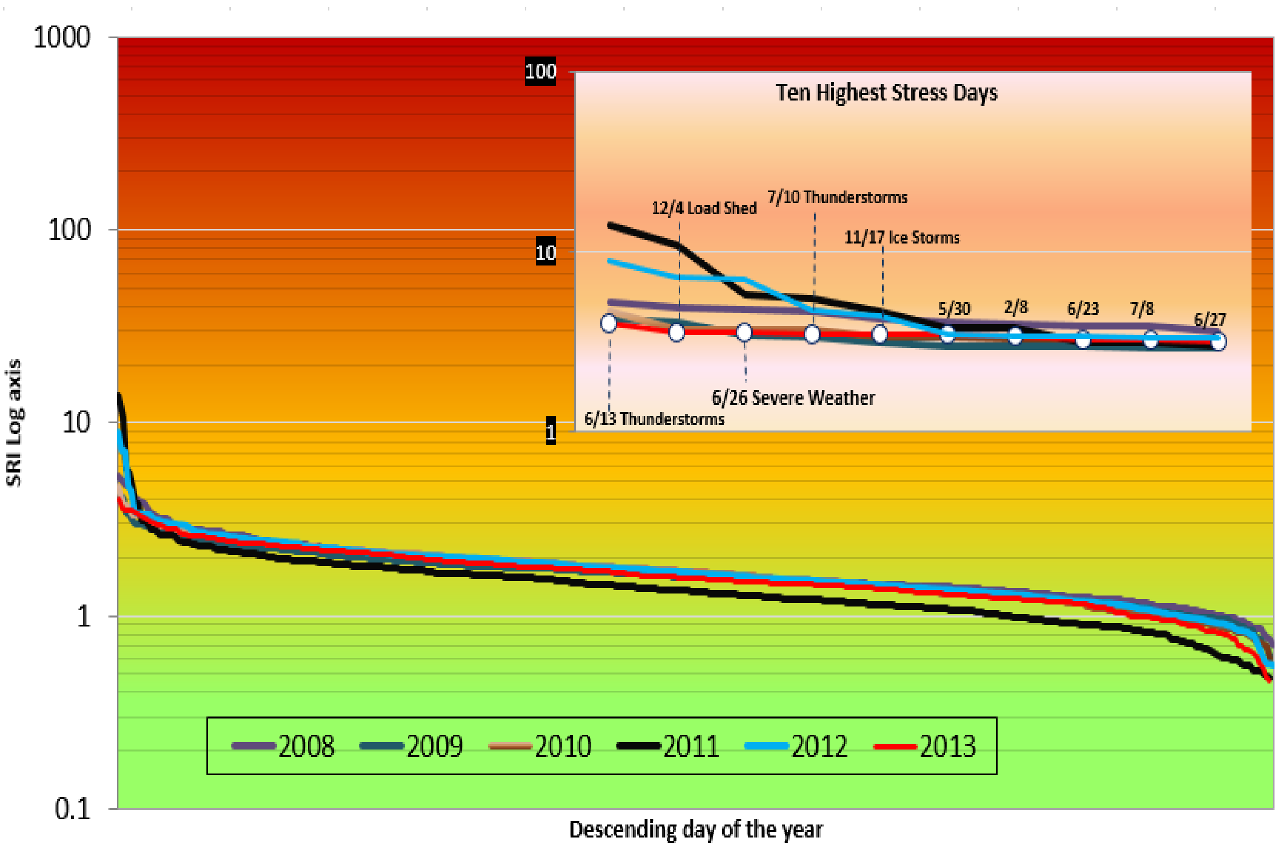


Figure 1.1: NERC Daily Severity Risk Index Sorted Descending by Year

Table 1.1: 2013 Top-Ten SRI Days							
Date	NERC SRI and Components				Weather Influenced (Y/N)	Cause Description	Interconnection
		Components and Weighting					
	SRI_{bps}	Generation (10%)	Transmission (30%)	Load Loss (60%)			
6/13/2013	4.1	14.5	4.4	2.1	Y	Severe Thunderstorms	Eastern
12/4/2013	3.6	11.1	1.7	3.3	Y	Cold/Load Shed	Western
6/26/2013	3.6	16.8	4.9	0.7	Y	Severe Weather	Eastern and Western
7/10/2013	3.5	18.9	3.0	1.2	Y	Severe Thunderstorms	Eastern
11/17/2013	3.5	7.9	3.5	2.8	Y	Severe Ice & Snow Storm	Eastern
5/30/2013	3.5	18.9	4.7	0.3	N	Power System Condition, Fire	Western and Eastern
2/8/2013	3.4	9.9	0.2	3.9	N	Equipment Failure	Eastern
6/23/2013	3.3	8.9	3.5	2.2	Y	Weather	Western
7/8/2013	3.2	14.8	5.5	0.2	Y	Rainfall Leading to Flooding	Eastern
6/27/2013	3.2	13.2	3.8	1.2	N	Fault and Equipment Failure	Western and Eastern

Steady Transmission System Availability and Metrics

Availability of the transmission system remains high with no statistically significant change in performance from 2008 to 2013. Operated at 200 kV and above, ac circuit availability is greater than 97 percent, and transformer availability is greater than 98 percent for the period of 2010–2013, the only years that planned outage data (an integral component in total availability) is available.

This availability includes both planned and unplanned outages. Planned outages for maintenance and construction have a long-term positive impact on transmission system reliability. AC circuit and transformer unavailability was well below 3 percent, as shown in Figures 1.2 and 1.3. The unavailability due to automatic sustained outages was 0.30 percent for ac circuits, and 0.10 percent for transformers. These relative percentages provide an indication of the overall availability of the transmission system operated at 200 kV and above.

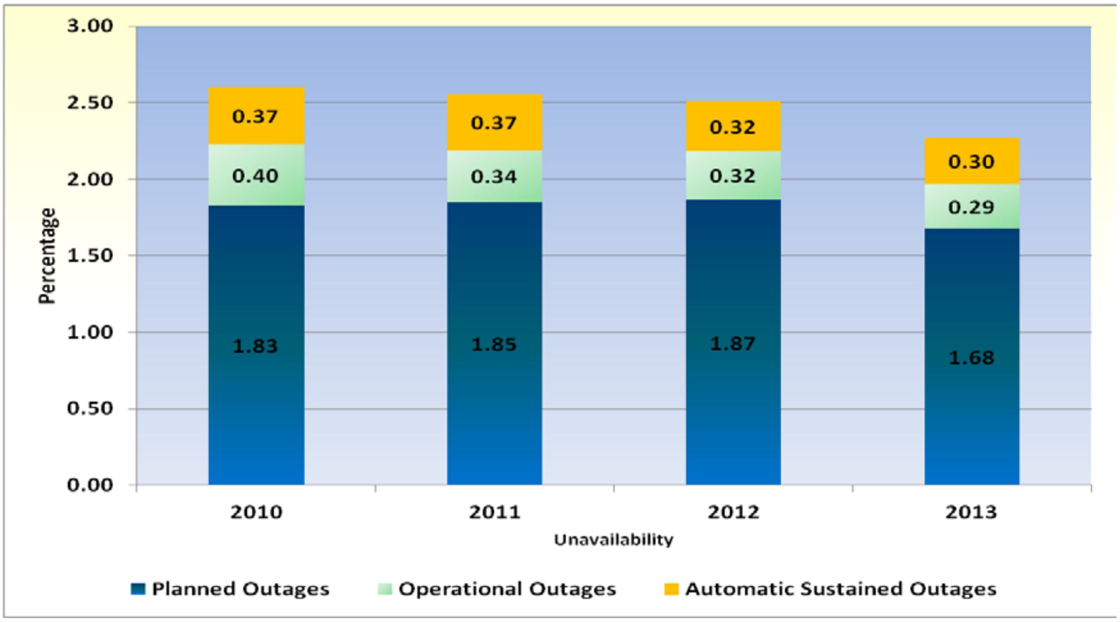


Figure 1.2: NERC Transmission AC Circuits Unavailability by Outage Type (2010–2013)

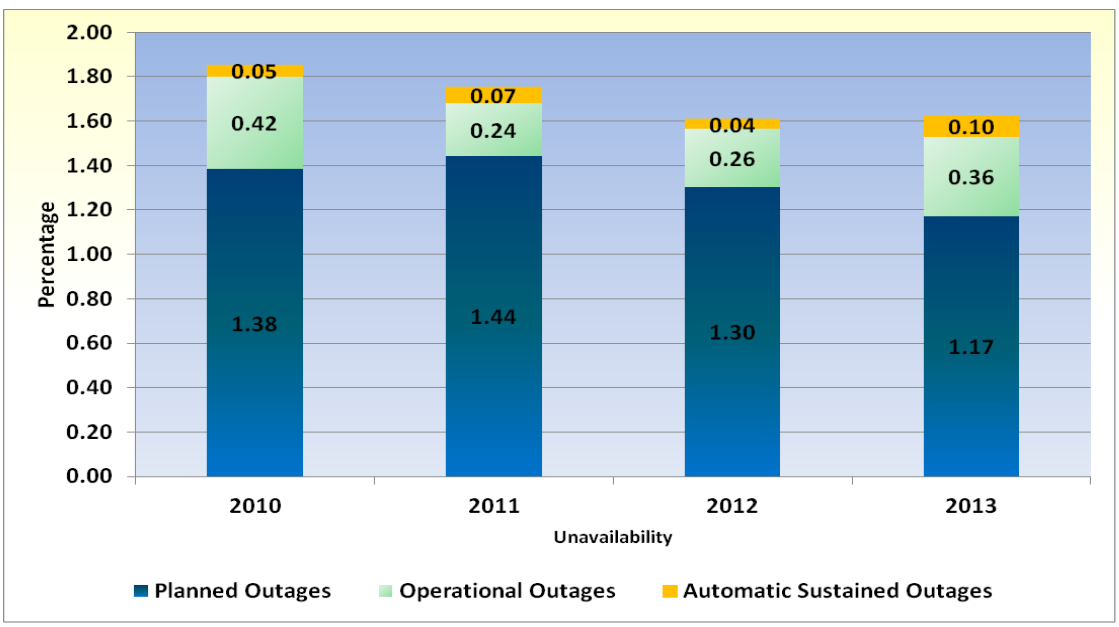
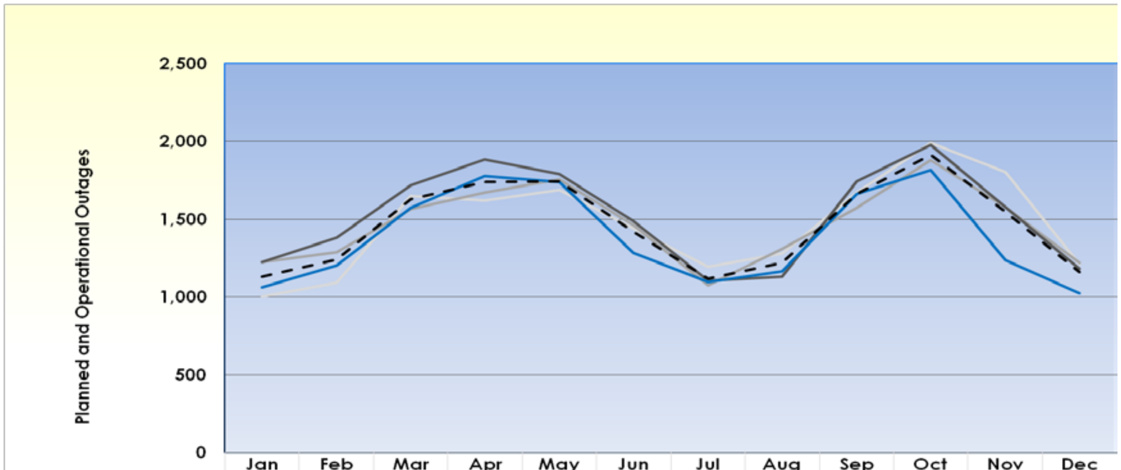


Figure 1.3: NERC Transmission Transformers Unavailability by Outage Type (2010–2013)

Figure 1.4 illustrates that during winter (December, January, and February) and summer (June, July, and August) months, the number of transmission planned and operational outages are lower compared to other months of the year, when most construction and maintenance work occurs.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	1,005	1,093	1,650	1,621	1,688	1,440	1,195	1,282	1,670	1,991	1,803	1,213
2011	1,225	1,287	1,567	1,670	1,758	1,464	1,076	1,308	1,573	1,879	1,577	1,222
2012	1,226	1,382	1,717	1,883	1,789	1,490	1,107	1,130	1,746	1,978	1,579	1,180
2013	1,062	1,202	1,575	1,779	1,738	1,286	1,095	1,166	1,665	1,816	1,239	1,025
4-Year Average	1,130	1,241	1,627	1,738	1,743	1,420	1,118	1,222	1,664	1,916	1,550	1,160

Figure 1.4: NERC Transmission Planning and Operational Outages by Month (2010–2013)

Overview of NERC Actions Supporting Sustained High Performance

NERC's Reliability Risk Management (RRM) group performs assessments (including real-time or near-real-time assessments) of the reliability and adequacy of the BPS and identifies potential issues of concern relating to system, equipment, entity, and human performance. RRM focuses on awareness of BPS conditions and events. The group analyzes events and addresses the most significant risks to BPS reliability, ensuring that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. The observations from RRM's focused situation awareness and event analysis activities are consistent with the broader conclusions above and provided context and depth to all 10 of the top SRI days as shown in Table 1.1.

In 2013, several standards projects were completed that support sustained high performance of BPS reliability by providing the data necessary for bulk transmission system analysis. The Modeling Data standards[24] provide a foundational framework for consistent data requirements and reporting procedures needed to develop planning horizon simulation models critical to support the analysis of the interconnected BPS's reliability. The standards establish clear expectations of who provides what data to whom to support each interconnection model construction and introduces Planning Coordinator-level data validation within each planning area. The Demand Data standard[25] provides authority for applicable entities to collect demand, energy, and related data to support reliability studies and assessments measuring whether there is an adequate amount of resources available to serve peak demand while also maintaining a sufficient margin to address operating events. This Reliability Standard enumerates the responsibilities and obligations of requestors and respondents of the data. The ATC standard[26] requires available transmission system capability to be determined to support the reliable operation

[24] MOD-032-1 and MOD-033-1, Modeling Data (MOD B), http://www.nerc.com/pa/Stand/Pages/Project2010-03ModelingData(MOD-B).aspx

[25] MOD-031-1, Demand Data (MOD C), http://www.nerc.com/pa/Stand/Pages/Project2010-04DemandData(MOD-C).aspx

[26] MOD-001-2, ATC Revisions (MOD A), http://www.nerc.com/pa/Stand/Pages/Project201205MODAAvailableTransferCapability.aspx

of the BPS, and that the methods and data underlying those determinations must be disclosed to those registered entities that need such information for reliability purposes.

In early 2014, NERC completed work on modifications to a standard on operator communications protocols, COM-002-4.[27] The purpose of the standard is to improve communications for the issuance of operating instructions with predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the BES. The standard addresses communications protocols for operating personnel in emergency and non-emergency conditions.

Key Finding 2: Frequency Response Remains Stable

NERC annually applies statistical tests to interconnection frequency response datasets,[28] including additional analyses on time of year, load levels, and other attributes. From 2009 to 2013, the Eastern Interconnection, ERCOT Interconnection, Québec Interconnection,[29] and Western Interconnection have shown steady frequency response performance, trending above the recommended IFRO at all times during the study period. The Eastern Interconnection data showed a slightly downward trend in frequency response; however, this trend is not statistically significant. It is important to continue to monitor these trends to determine whether any numbers approach or drop below the IRFO for any interconnection. The study methods and statistical results are summarized in Chapter 4 (ALR1-12) and detailed in Appendix B.

Overview of NERC Actions Supporting Sustained Frequency Response

FERC approved BAL-003-1 on January 16, 2014. This standard establishes a minimum frequency response obligation for each BA, provides a uniform calculation of frequency response and frequency bias settings that transition to values closer to natural frequency response, and encourages coordinated Automatic Generation Control operation. This standard, in partnership with BAL-001-2, maintains interconnection steady-state frequency within defined limits by balancing real power demand and supply in real time. BAL-003-1 will ensure that BAs take actions to maintain interconnection frequency, with each BA contributing its fair share to frequency control. BAL-001-2 is pending regulatory approval.

NERC is continuing development work in 2014 on the Reliability Standards that relate to frequency response. The Balancing Authority Reliability-Based Controls: Reserves project[30] is modifying BAL-002 to measure the ability of an entity to recover from a reportable event with the deployment of its reserves. The reliable operation of the interconnected BPS requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment. The Disturbance Monitoring project[31] is modifying PRC-002 to establish requirements for recording and reporting sequence-of-events (SOE) data, fault-recording (FR) data, and dynamic-disturbance-recording (DDR) data to facilitate analyses of disturbances. The proposed modifications to the standard will not specify what equipment must be used to capture this data but will focus on ensuring that the requisite data is captured. This will improve system reliability by providing personnel with necessary data to enable more effective analysis of events that affect the BES.

There were no reported Event Analysis Program[32] qualified events in 2013 where frequency response performance was cited as a causal factor for initiating or sustaining an event. NERC will examine incidents in 2013

[27] Operating Personnel Communications Protocols, http://www.nerc.com/pa/Stand/Pages/Op_Comm_Protocol_Project_2007-02.aspx
[28] Datasets described in the Frequency Response Initiative Report, October 2012 http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf
[29] Only Québec Interconnection 2011 and 2012 frequency response data is available.
[30] Phase 1 of Balancing Authority Reliability-based Controls: Reserves, http://www.nerc.com/pa/Stand/Pages/Project2010-14-1-Phase-1-of-Balancing-Authority-RBC.aspx
[31] Disturbance Monitoring, http://www.nerc.com/pa/Stand/Pages/Project_2007-11_Disturbance_Monitoring.aspx
[32] http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

where frequency response was below the IFRO to determine any actions that should be taken in response to the frequency response performance.

Recommendation
NERC will examine and develop root causes for incidents in 2013 where frequency response was less than the IFRO. NERC will determine additional actions, beyond those currently being worked on in NERC Standards, that should be taken to maintain and improve frequency response performance.

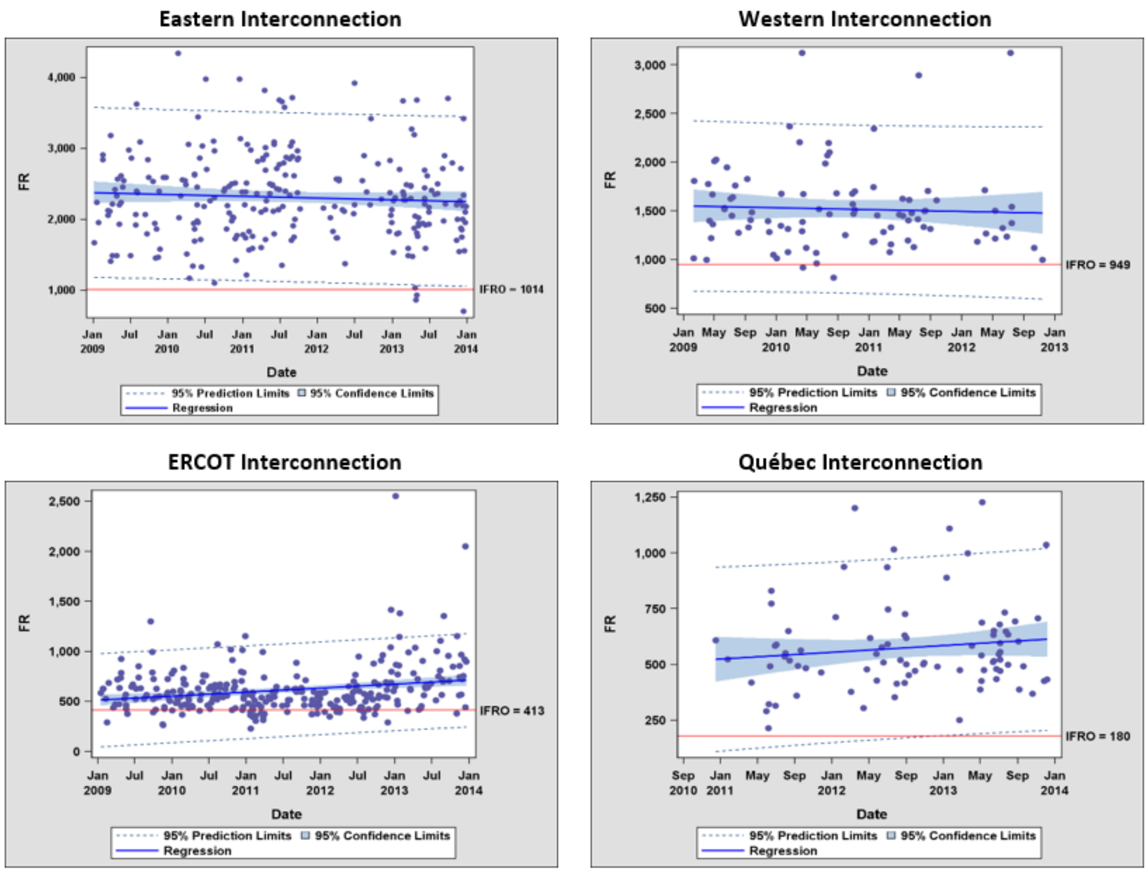


Figure 1.5: Interconnection Frequency Response Trend (2009–2013)

Key Finding 3: Protection System Misoperations Cause Transmission Events

Protection System Misoperation was identified in previous years as a cause code that has significant probability of occurrence and is positively correlated with transmission severity when outages do occur. Below are additional findings from analyses of misoperations from 2011 through 2013:

- Misoperation occurrences have been consistent over the past three years, with approximately 2,000 misoperations per year.
- The rate of misoperations, as a percentage of total operations, has remained consistent during this period at approximately 10 percent (i.e., roughly one in 10 operations is a misoperation).
- The three most common causes of misoperations remain the same (approximately 65 percent of misoperations are caused by settings/logic/design errors, communication failures, and relay failures).

Three datasets are available to better understand the impact of misoperations on reliability. One dataset is a database of all misoperations that occur on the BES (100 kV and above) that is collected on a quarterly basis by the Regions and NERC. This database provides a comprehensive set of data for all transmission and generation misoperations. It is submitted by the system protection owners and includes detailed information about the misoperation, including a description of the misoperation, its category, its causes, and the proposed mitigation and completion date.

A second dataset that is used to assess risk associated with misoperations is the event reports that are submitted to the Regions and NERC through the event analysis program document that was established by the Events Analysis Subcommittee (EAS). When misoperations are associated with reported system disturbances, NERC can then assess their actual impact on the BES and also identify whether they were causal or contributory to the event through cause coding.

A third source of misoperations reporting occurs through the TADS data collection. Misoperations that were identified as being caused by human error or relay failure are identified in TADS reporting. This occurs for transmission facilities operated at 200 kV and above.

Focusing the statistical analysis of the 2012–2013 TADS data on the transmission severity and initiating causes of TADS events yields the following results and observations:

- Excluding Weather-related and Unknown Initiating Cause Codes (ICC),[33] Misoperations is one of the two largest contributors to the transmission severity risk.
- TADS events initiated by Misoperations and Failed AC Substation Equipment ICCs have a greater expected severity than all other TADS ICC events.

In 2013, there were 71 transmission-related system disturbances that resulted in a NERC Event Analysis reported event. Of those 71 events, 47 (about 66 percent) had associated misoperations. Of these 47 events, 38 (about 81 percent) experienced misoperations that were contributory to or exacerbated the severity of the event. In several cases, multiple misoperations occurred during a single disturbance. Cause coding has not yet been completed for all 2013 events, but it is estimated that there were 60–75 misoperations associated with these 38 reportable events. Therefore, out of approximately 2,000 total misoperations in 2013, approximately 3.0 to 3.5 percent were causal to or exacerbated by the severity of reportable system disturbances.

Two complementary views of misoperations data have been provided in this report. Based upon the total number of misoperations experienced by the industry, the relationship between the Misoperations ICC and transmission risk, and the positive correlation between misoperations and transmission severity, understanding and reducing misoperations should remain a focus of NERC and industry participants.

Overview of NERC Actions Addressing System Protection Misoperations

NERC is continuing activity on several projects to address protection system misoperations. The Reliability Issues Steering Committee (RISC) has identified system protection reliability, uncoordinated protection systems, and protection system misoperations as top-priority risks to reliability. NERC has focused its Reliability Standards efforts in this area with the completion of the relay loadability standards[34] and continues work on relay misoperations[35] and coordination.[36] In addition, NERC staff is coordinating with the North American Transmission

[33] ICC - The Automatic Outage Cause Code that describes the initiating cause of the outage, page 16, Appendix 7, http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf

[34] Generator Relay Loadability and Transmission Relay Loadability, http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx

[35] Protection System (Misoperations), http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx

[36] Protection System Coordination, http://www.nerc.com/pa/Stand/Pages/Project-2007-06-System-Protection-Coordination.aspx

Forum to find ways to reduce protection system misoperations and develop methods to minimize their impact. NERC Event Analysis continues to examine system events to identify those that are impacted by protection system misoperations to determine if action is needed to address trends and common modes of misoperations.

Recommendation
NERC will complete development of Reliability Standard PRC-004-3 — Protection System Misoperation Identification and Correction. NERC will develop a plan and catalyze industry action to address the three most common causes of protection system misoperations (settings/logic/design errors, communication failures, and relay failures).

Key Finding 4: Substation Equipment Failures Impact Transmission Event Severity

As mentioned in Chapter 3, AC Substation Equipment Failures had the largest positive correlation with automatic transmission outage severity in 2013. The correlation is statistically significant: a pattern and underlying dependency exists between ac substation equipment failures and transmission outage severity. A similar observation was made in Key Finding #5 of the *State of Reliability 2013* report. NERC recommended that a small subject matter expert technical group be formed to further validate the findings and root causes to understand the contributing factors of ac substation equipment failures and provide solutions to improve performance. The AC Substation Equipment Task Force (ACSETF) was created to address high-priority reliability issues related to ac substation equipment. The ACSETF has gathered ac substation equipment failure data from multiple sources, including but not limited to the Event Analysis Program, TADS, a supplemental TADS survey conducted by the ACSETF, and the WECC trouble report dataset. The failure data is currently being analyzed by the ACSETF.

ACSETF Work Status

Based on the data reviewed through March of 2014, the ACSETF has observed:

1. The highest percentages of outages involve circuit breaker failures, as previously reported in the *State of Reliability 2013* report.[37]
2. The top-four sub-components that result in circuit breaker failures, in descending order of frequency, are: interrupters, mechanism, trip coil, and bushing.
3. Inherent in circuit breaker failure is an increased probability that additional BPS elements will also be out of service.
4. Inherent in transformer failure is an increased probability of longer outage duration.
5. Further data collection and analysis is needed, including maintenance strategies, bus configurations, and failure event SRI calculation.

The ACSETF will provide a summary of its analysis along with suggestions for improvement and other observations to the NERC PC and OC for review and approval. The final report is scheduled to be completed by December 31, 2014, and results are anticipated to be incorporated in *State of Reliability 2015* report.

Overview of NERC Actions Addressing AC Substation Equipment Failures

In addition, NERC is focusing on increasing awareness of this risk to reliability. For example, NERC developed the adequate level of reliability metric, ALR6-13 AC Transmission Outages Initiated by Failed AC Substation Equipment,

[37] http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2013_SOR_May%2015.pdf

to measure performance changes in failed ac substation equipment. The metric shows that outages per element demonstrates year-over-year improvement from 2011 to 2013; this is posted on NERC's website.[38]

Circuit breaker failures, in conjunction with another system fault, may lead to more BES facilities being removed from service than required to clear the original fault. High-voltage circuit breaker failures are one of the leading contributors of severe disturbances on the BES. When NERC identified a potential trend of 345 kV SF_6 puffer-type breakers failing, a Level 1 NERC Advisory was issued.[39]

Recommendation

NERC will assess the implementation and effectiveness of the Level 1 NERC Advisory issued to address 345 kV SF_6 puffer-type breaker failures. NERC will develop a plan with milestones to address the causes of substation equipment failures identified by the ACSETF. NERC will develop and facilitate data collection necessary to perform future analysis of substation equipment failures, as recommended by the ACSETF.

Key Finding 5: Use of Energy Emergency Alert Level 3 Declines

In 2013 there were seven Energy Emergency Alert (EEA) Level 3 events declared, which is significantly lower than the number that occurred in prior years. Additionally in 2013, changes were made to the metric ALR6-2 to include duration in hours that an EEA was in effect at any level and the amount of load shed that was necessitated by an EEA Level 3 event.

This data collection was first performed for 2013 EEA data, and it showed that of the seven EEA Level 3 events declared, only one resulted in any amount of load shed. The other six fell into two categories. One category pertained to significant unplanned outages of resource supply due to generator trip or equipment failure—either the unplanned loss of one or more generation resources, or the unplanned loss of a major transmission facility that supplied generation into an area. These included quickly evolving events in which the entity had to use its reserves to serve its load and had to prepare for load shed to meet the next possible contingency. The other category consisted of events in which transmission limitations in the form of Transmission Loading Relief (TLR)[40] events were in place and were affecting entities that rely upon import transactions to serve their load. These events did not involve unplanned loss of generation or equipment failures; rather, they occurred as loading increased over a period of time and the affected Transmission Operator (TOP) responded by requesting various levels of TLR relief. The entities in this category used the EEA Level 3 Alert to protect their firm transactions, to avoid having to reduce load, and to call upon reserve-sharing provisions to restore reserves.

Throughout 2013, there were eight instances of firm load shedding not driven by EEA Level 3 events. These eight load-shedding instances were distributed across four distinct events. Of the eight instances where firm load was shed, five instances were required to mitigate post-contingency transmission facility overloads, one instance was to mitigate actual transmission facility overloads and low voltages following a major transmission system disturbance, and one instance was to mitigate non-convergence of state estimation, indicating an unknown operating state. In all eight instances, the use of load shedding was successful at preventing greater and more widespread impacts.

Recommendation

NERC will analyze system events that resulted in firm load shedding to determine any common causes or trends that warrant action.

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[38] Reliability Indicators: Automatic Outages Initiated by Failed AC Substation Equipment / Automatic Outages Initiated by Failed AC Circuit Equipment,
http://www.nerc.com/pa/RAPA/ri/Pages/Automatic-OutagesInitiatedbyFailedACSubstationACCirc.aspx

[39] Industry Advisory: 345kV Breaker Failures Initial Distribution: August 27, 2013

[40] http://www.nerc.com/pa/rrm/TLR/Pages/default.aspx

Recent Changes

The state of reliability is an ever-changing landscape. A number of activities were pursued in 2013 to further improve the metrics and assessments:

Modified SRI calculation

In 2013, the Performance Assessment Subcommittee received concerns that the SRI calculation was dominated by loss-of-load impacts. Since the weather-related events often have distribution-related outages to a greater degree than generation or transmission impacts, the SRI calculation was modified to remove most of the distribution facility outage causes from the load-loss component of the calculation. Only load loss caused by loss of supply from either the generation or transmission system is now included in the SRI calculation. This report describes the new calculation of SRI, referred to as SRI_{bps}. Consistent with observations in prior state of reliability reports, severe weather remained a major contributor to many of the high-severity days.

Retired KCMI

The PAS reviewed the existing Key Compliance Monitoring Index (KCMI)[41] and in collaboration with the Compliance and Certification Committee (CCC) retired it in 2013. Prior state of reliability reports noted that the trend for this index continued to reflect fewer violations of standards. It became increasingly difficult to update the standards violations that were included in the KCMI to stay current with evolving Reliability Standards and provide a meaningful metric. As a part of NERC's three-element view of risk, compliance violations associated with Reliability Standards remain an important part of the analysis of reliability. Therefore, an effort has begun to create a new metric to track performance with regard to violations of Reliability Standard requirements that are considered to have a serious risk to the BES. The expectation is that the replacement of KCMI in 2014 with an improved compliance metric would provide more meaningful information on standards violations with a potentially serious impact to reliability.

Revised Adequate Level of Reliability Definition

In late 2012, NERC adopted a revised definition of Adequate Level of Reliability, which forms the basis for the reliability indicators that are used as metrics to evaluate the performance of the BES. The seven performance objectives and associated expected performance outcomes were developed to encompass NERC's responsibility to ensure reliability of the BES. This year's state of reliability report contains a mapping of the seven performance objectives to the existing performance metrics. Also, a new naming convention has been proposed to move from the former six-element definition to the new definition, which has seven categories of performance objectives.

Modification of Metrics

Finally, in the annual review of the existing metrics, efforts were made to consolidate metrics that were similar, and to add dimension to metrics in areas where additional information may provide insight, particularly in capturing duration of events and magnitude of impact to the BES with load interruption. To meet these goals, two metrics were retired, and several were modified to either add additional criteria or provide additional dimensions of data collection to the metrics. These modified metrics are included in more detail in Chapter 4.

Additional NERC Initiatives

NERC continues to develop solutions to evolving threats to reliability. The BPS is a highly interconnected system with some remaining challenges, including weather (e.g., droughts, floods, severe winter) and the potential for major cyber and physical attacks. Under the direction of the CIPC, the PAS is collaborating with the Bulk Electric System Security Metrics Working Group to develop security performance metrics.

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[41] http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2013_SOR_May%2015.pdf KCMI definition, page 42

NERC's Standards department continues to review the standards to improve performance of the BPS via the Standards Development Plan.[42] This work focuses on improving the quality and content of standards while addressing key system risks as identified through analysis of existing trends.

In response to FERC directives, through 2014 NERC will continue to develop modifications to the CIP Reliability Standards when approving Version 5.[43] NERC is also developing a standard on Physical Security,[44] which will require owners or operators of the BPS, as appropriate, to identify facilities on the BPS that are critical to the reliable operation of the BPS. Additionally, owners or operators of those identified critical facilities will develop, validate, and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities.

Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the North American BPS will require significant changes to traditional methods used for system planning and operation. The amount of variable renewable generation is expected to grow considerably as policy and regulations on greenhouse gas emissions are being developed and implemented by federal authorities and individual states and provinces throughout North America. Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS reliability. Operators will require new tools and practices, including potential enhancements to NERC Reliability Standards or guidelines to maintain BPS reliability.

NERC is continuing its focus on refining ICCs, including further analysis on the "Unknown" cause code. In the *State of Reliability 2013* report, transmission outages with an ICC of Unknown contributed to 19 percent of all TADS events. A recommendation was made to provide additional guidance to those entities reporting sustained outages with an ICC of Unknown.

The subject of TADS outages reported with initiating cause as Unknown was reviewed and discussed with the TADS Working Group (TADSWG). Results of statistical analyses on historical TADS event data (2008–2012) was presented by NERC staff and discussed at recent TADSWG meetings. The results indicated that:

- TADS events with ICCs of Lightning, Unknown, Contamination, and Foreign Interference tend to initiate Momentary Events.
- There is a statistically significant negative correlation between sustained events and TADS events with ICCs of Lightning, Unknown, Contamination and Foreign Interference.
- There is a statistically significant positive correlation between Sustained events and the following ICCs: Human Error, Failed AC Substation Equipment, Failed AC Circuit Equipment, Weather Excluding Lightning, Fire, Failed Protection System Equipment, Other, and Power System Condition.
- Approximately 40 percent of TADS event data are momentary events (an automatic outage less than one minute).

Further analysis has revealed that approximately 60 percent of TADS events with ICC Unknown are momentary events.

[42] NERC Reliability Standards Development Plan, http://www.nerc.com/pa/Stand/Pages/ReliabilityStandardsDevelopmentPlan.aspx
[43] Critical Infrastructure Protection Standards Version 5 Revisions, http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx
[44] Physical Security, http://www.nerc.com/pa/Stand/Pages/Project-2014-04-Physical-Security.aspx

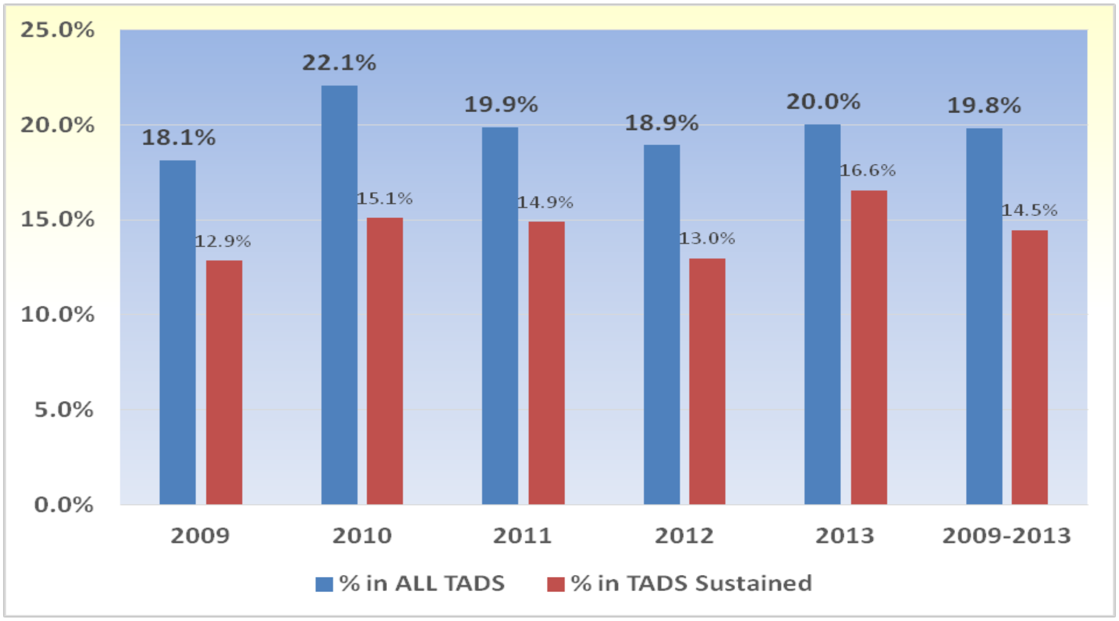

Figure 1.6: Percentage of Unknown Events in all TADS Events vs. in TADS Sustained Events

It is often not possible to confidently determine an ICC for momentary outages, so focus should be on sustained outage events with ICC of Unknown. It is possible that in certain cases, coding sustained outages as Unknown may be due to a lack of clarity on the part of reporting entities for coding events. The TADSWG continues to address questions from TADS reporting entities pertaining to TADS event coding. Specific outage scenarios are reviewed and clarifications to the TADS Data Reporting Manual are applied. These specific changes are reviewed during TADS training sessions, which are held annually with the TADS reporting entities. The TADSWG will continue to monitor the TADS outage data for the purpose of enhancing the cause coding process to minimize the number of sustained outages with ICC as Unknown. NERC will continue to identify and work with entities that report relatively high proportions of Unknown outages to resolve any outage coding issues.

Chapter 2 – Daily Performance Severity Risk Assessment

Overview

The PAS previously developed[45] Figure 2.1 to depict the metrics used to measure the major categories of risks to reliability.

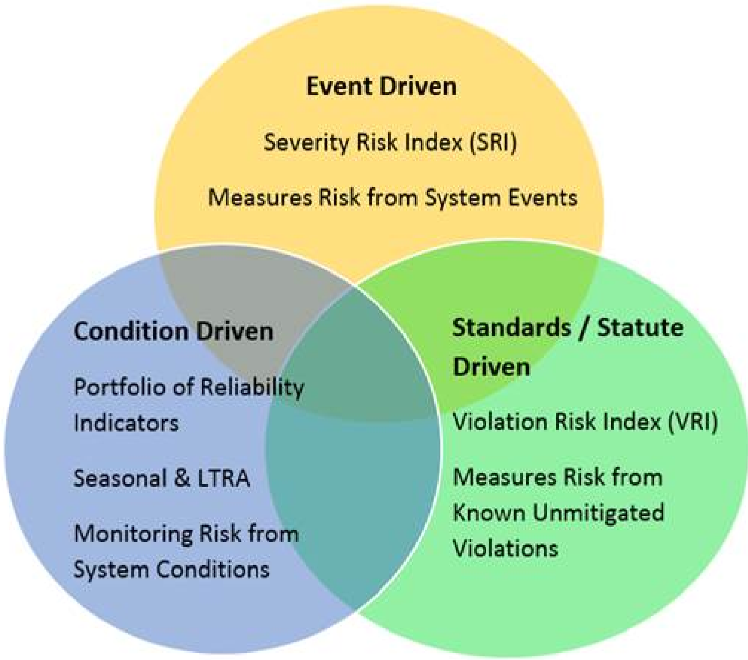

Figure 2.1: Conceptual Risk Model for Bulk Power System

The PAS also developed metrics designed to measure the performance of each of the categories of risk. While some of these metrics are still evolving, the use of the SRI[46] has proven to be a useful way of quantifying the daily performance of the BPS.

During 2013, the PAS undertook significant efforts to enhance the SRI, and it was recognized that the method of calculating the value relied on data that may not have aligned optimally with the index. As a result, revised data was developed, whereupon calculations were modified and results were tested. The SRI was calculated by using the historic method, labeled SRI_{OLD}, then compared against the revised method, labeled SRI_{bps}. These results were shared, along with the recommendation by the PAS to the OC and PC, who approved the revised calculation.

This year's analysis relies on this modified calculation, and all use of SRI_{OLD} has been discontinued in this year's *State of Reliability* report.

Key conclusions were:

- The performance on high-stress days was as good as that recorded in 2009 and 2010, which were the best years since data collection began.
- Contrary to prior years, load loss events were not the primary indicator of a high SRI day; in fact, three of the top-10 days for the year appeared to be driven by generation and transmission outage performance and did not significantly involve load loss (load loss severity was less than 1.0).

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[45] Integrated Reliability Index Concepts, http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf

[46] SRI Enhancement paper, http://www.nerc.com/comm/PC/Performance Analysis Subcommittee PAS 2013/SRI Enhancement Whitepaper.pdf

- There were several high-stress days resulting from extreme Weather events. In general, the SRI correctly correlated with those events, and the power system—while stressed—responded well.
- The majority of the top-10 most severe days in 2013 were initiated or exacerbated by Weather (seven of the 10 days).
- There were no high-stress days (SRI greater than 5.0) in 2013.
- For SRI values less than 5.0, 2013 had better average performance than all years except 2008, where its average value was very close to the 2008 average value.
- Generation outages contribute substantially to daily SRI_{bps} values.

NERC Assessment

Figure 2.2 captures the daily SRI_{bps} values from 2008 to 2013. The SRI is comprised of three key components: generation severity, transmission severity, and load-loss severity. For context throughout this report, each of these severity measures is calculated based on certain assumed and average values and does not rely on individual analyses that measured the specific impact of any given element's function. In particular, generation severity reflects the generation unavailability of a given unit with a plant capacity as a percentage of all available plant capacity. Transmission severity reflects the unscheduled availability of a particular TADS element for which the impact is calculated by a voltage-weighted value divided by the total inventory of TADS elements. Load-loss severity is calculated as an average customer usage at peak for the day the load-loss event occurred. The inset in Figure 2.2 highlights the highest stress days experienced in 2013 from the left side of the SRI curve.

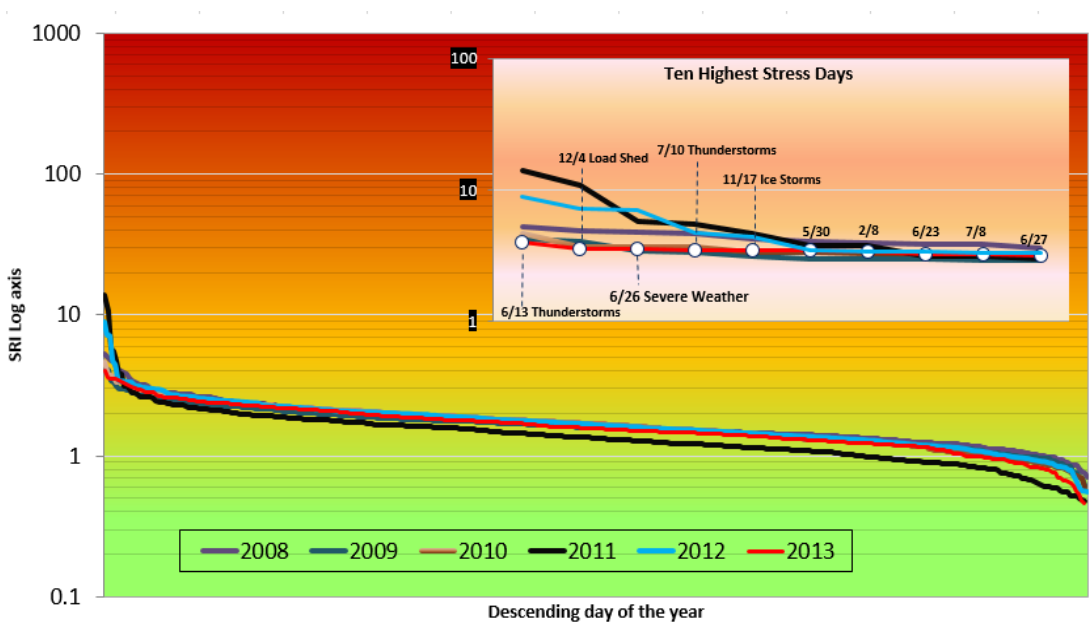

Figure 2.2: NERC Annual Daily Severity Risk Index Sorted Descending

As the year-to-year performance is evaluated in Figure 2.2, certain portions of the graph become relevant for specific analysis. First, the left side of the graph, where the system has been substantially stressed, should be considered in the context of the prior years' high-stress days. Next, the slope of the central part of the graph may reveal year-to-year changes in performance for the majority of the days of the year and demonstrate routine system resilience. Finally, the right portion of the curve may also provide useful information about how many days with lower SRIs occurred during any given year compared to another. The transition to SRI_{bps} allows the entire range of the curve to be used. Prior versions interpreting the right side of the curve may have been misleading, since load-loss calculations were not able to be performed for each calendar day of the year. As well, the left-hand side of the graph, with the inclusion of distribution-related load-loss events, may have overstated the impact of the load-loss component that pertains to the BPS.

Table 2.1 provides a historical summary of the top-10 SRI_{bps} days. When comparing the values to those in previous state of reliability reports, consider that this summary is based on the updated SRI_{bps} methodology calculation.

Table 2.1: 2013 Top-Ten SRI Days

Date	NERC SRI and Components				Weather Influenced (Y/N)	Cause Description	Interconnection
		Components and Weighting					
	SRI_{bps}	Generation (10%)	Transmission (30%)	Load Loss (60%)			
6/13/2013	4.1	14.5	4.4	2.1	Y	Severe Thunderstorms	Eastern
12/4/2013	3.6	11.1	1.7	3.3	Y	Cold/Load Shed	Western
6/26/2013	3.6	16.8	4.9	0.7	Y	Severe Weather	Eastern and Western
7/10/2013	3.5	18.9	3.0	1.2	Y	Severe Thunderstorms	Eastern
11/17/2013	3.5	7.9	3.5	2.8	Y	Severe Ice & Snow Storm	Eastern
5/30/2013	3.5	18.9	4.7	0.3		Power System Condition, Fire	Western and Eastern
2/8/2013	3.4	9.9	0.2	3.9		Equipment Failure	Western
6/23/2013	3.3	8.9	3.5	2.2	Y	Weather	Western
7/8/2013	3.2	14.8	5.5	0.2	Y	Rainfall Leading to Flooding	Eastern
6/27/2013	3.2	13.2	3.8	1.2		Fault and Equipment Failure	Western and Eastern

In 2013 there were no days that the SRI_{bps} score exceeded 5.0, which is an indicator of a “noteworthy” day. A handful of days are identified on the inset. These include the five days in 2013 with the highest SRI_{bps} score, all of which have an SRI value less than 4.5. The year 2013 was comparable to 2009 and 2010, which were the best years recorded since this data began being collected.

Table 2.1 lists the 10 event dates with highest daily SRI values in 2013 and indicates the component contribution to the SRI_{bps}. The SRI_{bps} results were compared against Form OE-417 data to determine which ones were weather-related.[47] This comparison is shown on Table 2.2. Seven of the top-10 SRI days were weather-influenced, as compared to all of the top-10 SRI days in 2012.

Table 2.2: OE-417 Event Reports versus Load Loss Severity

Date Event Began	Date of Restoration	Area Affected	NERC Region	Event Type	Demand Loss (MW)	Number of Customers Affected	Customer Load Loss (mw) Associated with Significant SRI Day	Feed CAIDI	Restoration Promptness CAIDI Factor	Load Loss SRI	SRI Date
2/8/2013	2/8/2013	District of Columbia; Prince George's County Maryland	RFC	Equipment Trip & Failure	140	52,000	0.01017638	2,356	1	3.8721	2/8/2013
3/3/2013	3/3/2013	Merced County, California	WECC	Transmission System Interruption	300	58,850	0.00886310	691	1	1.2318	3/3/2013
6/13/2013	6/13/2013	District of Columbia; Maryland	RFC	Loss of 300+ MW Load; Severe Weather - Thunderstorms	700	40,000	0.01140619	1,462	1	2.1243	6/13/2013
6/13/2013	6/14/2013	Southern Company Territory	SERC	Severe Weather - Thunderstorms	550	165,798					
6/13/2013	6/14/2013	Richmond Metro area, Virginia	SERC	Severe Weather - Thunderstorms	900	283,000					
6/13/2013	6/14/2013	Western Piedmont North Carolina	SERC	Severe Weather - Thunderstorms	1,000	175,000					
6/13/2013	6/14/2013	Central and Eastern North Carolina	SERC	Severe Weather - Thunderstorms	Unknown	53,000					
6/23/2013	6/24/2013	Central Coast California	WECC	Severe Weather - Fog	Unknown	148,000					
6/24/2013	6/25/2013	Illinois	RFC	Severe Weather - Thunderstorms	Unknown	283,451	0.01332191	2,220	1	2.2356	6/23/2013
6/24/2013	6/26/2013	Indiana	RFC	Severe Weather - Thunderstorms	Unknown	86,615	0.01218406	850	1	1.1931	6/27/2013
7/10/2013	6/28/2013	South Eastern Michigan	RFC	Severe Weather - Thunderstorms	Unknown	138,000					
7/10/2013	7/11/2013	AEP Ohio Power Footprint	RFC	Severe Weather - Thunderstorms	N/A	122,314	0.01319868	928	1	1.1982	7/10/2013
8/23/2013	8/23/2013	No Report Submitted					0.01109535	1,693	1	1.1916	8/23/2013
8/25/2013	8/25/2013	No Report Submitted					0.01172407	1,371	1	1.3877	8/25/2013
9/15/2013	9/15/2013	No Report Submitted					0.00989165	1,571	1	1.2427	9/15/2013
11/1/2013	11/1/2013	No Report Submitted					0.00908129	848	1	1.1747	11/1/2013
11/17/2013	11/20/2013	Michigan	RFC	Severe Weather - Ice and Snow Storm	Unknown	325,325					
11/17/2013	11/17/2013	Rochelle, Indiana	RFC	System-wide voltage reductions of 3 percent or more	38	7,500					
11/17/2013	11/20/2013	Central Indiana	RFC	Severe Weather - Tornadoes	535	61,705					
11/17/2013	11/21/2013	Entire Lower Peninsula Michigan	RFC	Severe Weather - Thunderstorms	Unknown	50,000					
11/17/2013	11/20/2013	Central Missouri, Central Illinois	SERC	Severe Weather - Tornadoes	Unknown	200,000					
11/17/2013	11/20/2013	North Central Indiana	RFC	Severe Weather - Thunderstorms	Unknown	75,065					
11/17/2013	11/18/2013	Indiana, Michigan	RFC	Severe Weather - Thunderstorms	Unknown	77,346					
11/17/2013	11/17/2013	Entire ComEd Territory Illinois	RFC	Severe Weather - Thunderstorms	Unknown	190,000	0.01116756	1,604	1	2.7934	11/17/2013
12/4/2013	12/4/2013	Idaho Falls Area Idaho, Utah-Idaho Border Utah	WECC	Load Shed 100+ MW	150	Unknown	0.00958207	1,905	1	3.2665	12/4/2013

[47] OE-417 E-Filing System Training Reference Guide, https://www.oe.netl.doe.gov/docs/OE417_submission_instructions.pdf

Figure 2.3 shows each day's SRI. Note that Figure 2.3 presents the historic top-10 days with an Event ID label that refers to column 1 of Table 2.3. A general normal range of performance can be established from historic data. Days that were extreme can be detected by their deviation from that normal level. During 2013, there do not appear to be as many extreme days as have occurred in prior years.

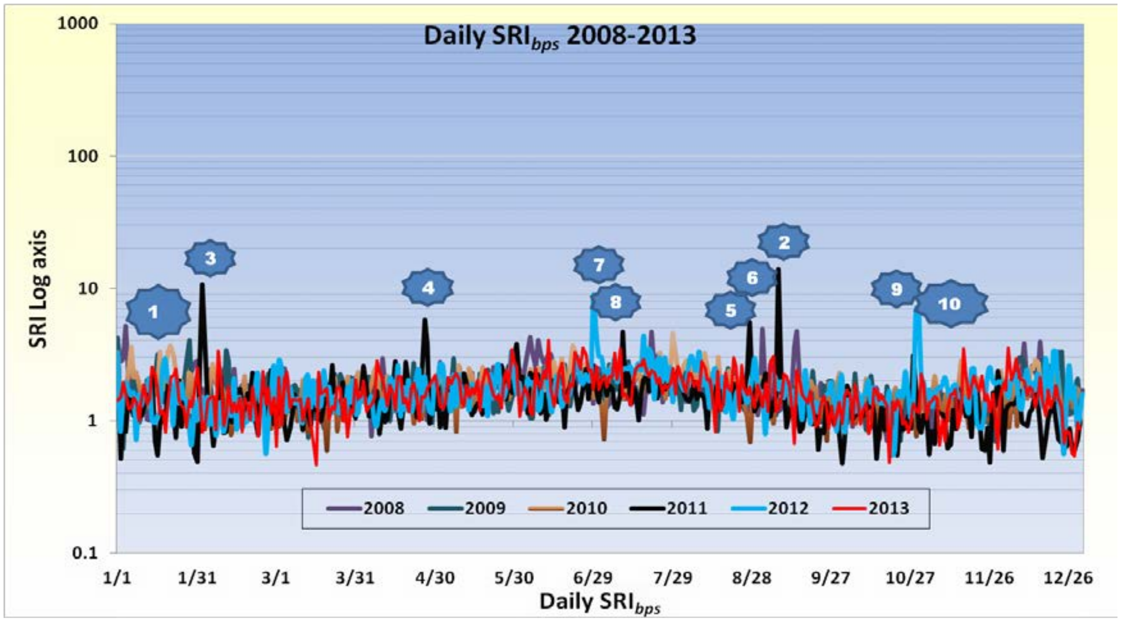

Figure 2.3: NERC Daily SRI (2008–2013)

Table 2.3: Top-10 SRI$_{bps}$ Days (2008-2013)				
Event ID	**Date**	**Event Ranking**	**SRI bps**	**Description**
1	1/4/2008	8	5.30	Winter Storm
2	9/1/2008	9	4.90	Hurricane Ike
3	2/2/2011	2	10.80	Cold Weather Event
4	4/27/2011	6	5.80	Tornadoes, Severe Storm
5	8/28/2011	7	5.60	Hurricane Irene
6	9/8/2011	1	14.00	Southwest Blackout
7	6/29/2012	3	8.90	Thunderstorm Derecho
8	6/30/2012	10	4.70	Thunderstorm Derecho
9	10/29/2012	5	7.00	Hurricane Sandy
10	10/30/2012	4	7.20	Hurricane Sandy

Figure 2.4 shows annual cumulative performance of the BPS. If a step change occurs on the graph, it represents a stress day as measured by the SRI.

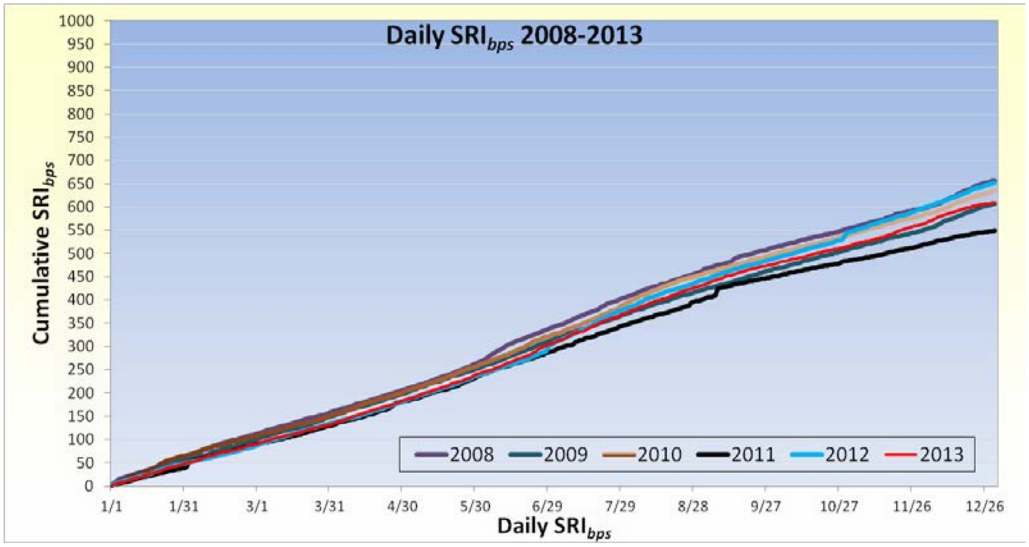

Figure 2.4: NERC Cumulative SRI (2008–2013)

Figure 2.5 breaks down the 2013 cumulative performance by BPS segment. The largest components are generation, transmission, and load loss, in that order. In Figure 2.4, the load-loss component shows day-to-day loss events but does not demonstrate any significant step changes, which was substantiated by the OE-417 data that was reviewed.

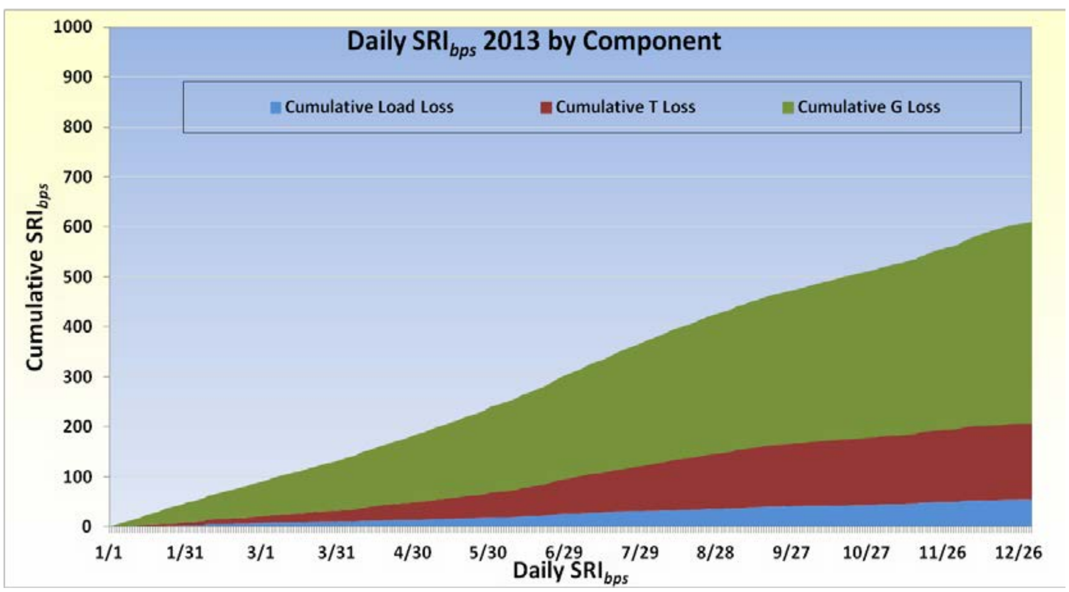

Figure 2.5: NERC Cumulative SRI by Component for 2013

Overall, 2013 had a lower SRI_{bps} score than 2008 and 2011 and was similar to 2009 and 2010. Also, the new calculation of SRI_{bps} shows that fewer stress days occurred in 2013 and that weather continues to contribute majorly to stress days. Additionally, it appears that with the modified method of calculating SRI_{bps}, generation severity plays a substantial role in the daily summary values as measured by SRI_{bps}. Future state of reliability reports will contain information assembled and analyzed from GADS, which is likely to bring greater understanding to these facilities and their role assessing the reliability of the BPS.

Chapter 3 – Risk Issue Identification and Transmission Severity Analysis

Overview

NERC uses disturbance event and equipment availability datasets to identify significant risk clusters to support making risk-informed decisions, prioritizing issues, and aligning resources to address those issues. The risk concentration areas enable NERC to identify priority projects that provide coordinated and effective solutions to identified risks to the reliability of the BPS. This chapter presents a conceptual framework using statistical analysis of transmission outage data to identify the top risks to the BPS. This transmission outage data is based on the data collected using the ICC identification provided by the NERC TADSWG. This framework and these risk analysis methods can be applied using other reliability datasets to further investigate risk concentration areas.

Based on the 2009–2013 automatic transmission outage data, the two significant risk clusters identified in this chapter are:

1. Protection system misoperations
2. AC substation equipment failure

In the *State of Reliability 2013* report, Misoperations (as an augmented ICC) were found to have the largest positive and statistically significant correlation with 2012 automatic transmission outage severity. This year's analysis shows that ac substation equipment failures now have the largest positive and statistically significant correlation with 2012–2013 automatic transmission outage severity. In addition, while these two ICCs remain the most statistically significant correlation with 2013 automatic transmission outage severity, the expected transmission severity associated with each of these ICCs has decreased from 2012's findings.

Failed AC Substation Equipment as an ICC was found statistically significant and positively correlated with 2009–2013 automatic transmission outage severity. Events initiated by Failed AC Substation Equipment are the largest contributor to the 2009–2013 transmission severity, excluding weather-related and unknown events. Chapter 5 contains a discussion of event analysis that shows that circuit breaker failures were reported as the most often failed equipment inside ac substations. A deeper investigation into the root causes of circuit breaker failures that contribute to disturbance events continues to be a high priority.

NERC is in the process of revising a number of Reliability Standards involving protection systems.[48] In addition, NERC has documented lessons learned from Generator Owners (GOs) and Transmission Owners (TOs) that achieve high protection system performance. In 2014, NERC staff is coordinating with the North American Transmission Forum to find ways to reduce protection system misoperations and develop ways to minimize the impact of misoperations.

Study Method

Defining BPS Impact from Transmission Risk

As described in Chapter 2, the SRI was developed to quantitatively compare events. The SRI is the calculation of a daily index that includes a component related to transmission system outages. The TADS outage data is used to populate the transmission outage impact component of the SRI. Since transmission outages are a significant contributor to the SRI, this chapter focuses on categorizing the individual transmission events based on TADS outage ICCs. A complete description of this methodology is contained in Appendix A.

48 http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx

Determining Initiating Causes and Probability

TADS events are categorized by ICCs. The ICCs facilitate the study of cause-effect relationships between each event's ICC and the severity of the event. As shown in Figure 3.1, for single-mode outage TADS events, the outage ICC is selected for the event's ICC. For common or dependent-mode TADS events, logical rules were applied to determine the initiating outage. The ICC is used to determine the event's ICC.

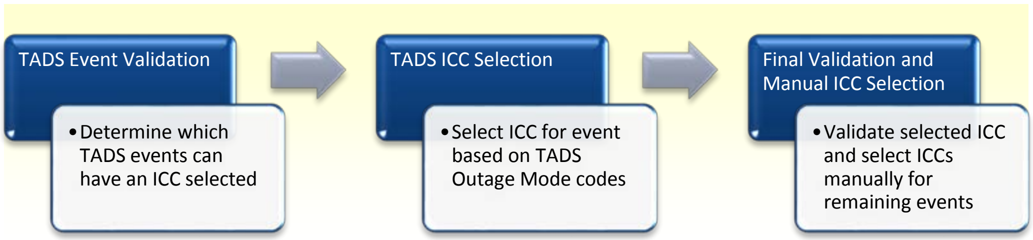

Figure 3.1 TADS Event Initiating Cause Code Selection Procedure

For TADS events initiated by a common cause, the probability[49] of observing the initiation of an event during a given hour is estimated using the corresponding historical event occurrences reported in TADS. Namely, the probability of the occurrence of the event is the total number of a given type of event observed during the historical data period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities for all events is equal to the estimated probability of any event during a given hour. With the development of the transmission severity measure and TADS event ICCs, it is possible to statistically analyze the most recent five years of TADS data (2009–2013). The analysis shows which ICCs result in the highest transmission severity and finds significant changes in transmission severity by ICC over time.

Determining Relative Risk

Studies were performed to determine the correlation between each ICC and transmission severity, and whether a statistically significant confidence level could be established. This process is demonstrated in Figure 3.2. Then, sample distributions were studied to determine any statistically significant pair-wise differences in expected transmission severity between ICCs, including a time trend analysis where applicable. Finally, the relative risk was calculated for each ICC group. A description of this methodology is provided in Appendix A.

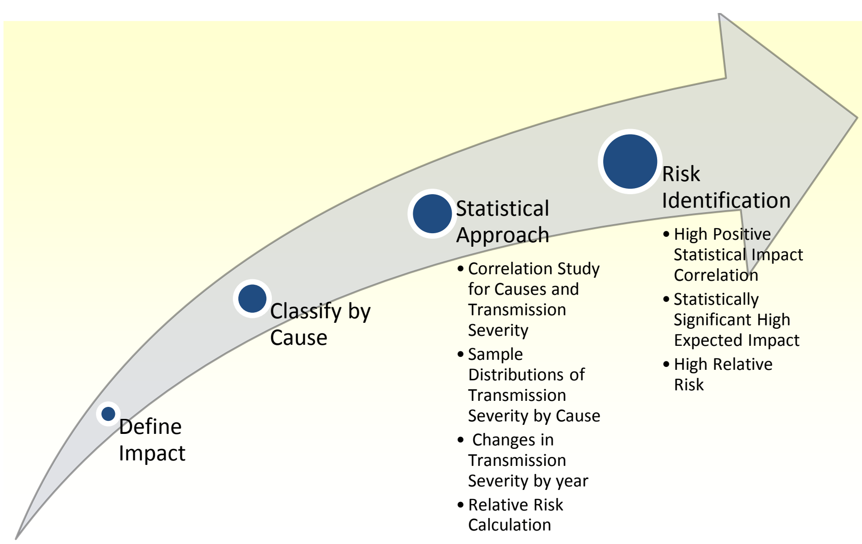

Figure 3.2: Risk Identification Method

[49] Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration.

Risk Identification Findings

2009–2013 Combined Study

TOs provide transmission performance information using the NERC TADS process. The data used in these studies includes momentary and sustained automatic outages of ac transmission circuits (overhead and underground) that operate at voltages greater than or equal to 200 kV.

Table 3.1 lists a total count of TADS events by ICC for 2009–2013. The three largest groups of events correspond to the following ICCs: Lightning, Unknown, and Weather Excluding Lightning. The next four groups of events are initiated by Human Error, Failed AC Circuit Equipment, Failed AC Substation Equipment, and Failed Protection System Equipment.

Table 3.1: TADS Outage Events by ICC (2009–2013)

Initiating Cause Code	2009	2010	2011	2012	2013	2009–2013
Lightning	789	741	822	852	814	**4018**
Unknown	673	821	782	710	712	**3698**
Weather Excluding Lightning	534	673	539	446	434	**2626**
Human Error	291	305	291	307	280	**1474**
Failed AC Circuit Equipment	257	277	306	261	248	**1349**
Failed AC Substation Equipment	266	238	289	248	192	**1233**
Failed Protection System Equipment	229	234	234	226	188	**1111**
Foreign Interference	199	173	170	170	181	**893**
Contamination	96	145	132	160	152	**685**
Power System Condition	112	74	121	77	109	**493**
Fire	92	84	63	106	130	**475**
Other	107	84	91	104	64	**450**
Vegetation	29	27	44	43	36	**179**
Vandalism, Terrorism, or Malicious Acts	4	6	5	10	9	**34**
Environmental	5	11	5	4	8	**33**
Failed AC/DC Terminal Equipment	1	2	0	0	0	**3**
All TADS Events	**3705**	**3917**	**3934**	**3753**	**3557**	**18866**
All with ICC Assigned	**3684**	**3895**	**3894**	**3724**	**3557**	**18754**

Almost all ICC groups have a sample size sufficient to be used for statistical analysis. However, four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental, and Failed AC/DC Terminal Equipment) have an insufficient sample size and are grouped together in this report and labeled “Combined Smaller ICC groups” for statistical analysis. They are then compared as a group to other ICC groups and studied for annual changes in transmission severity.

Figure 3.3 shows the correlation between calculated transmission severity and each ICC. A red bar in Figure 3.3 corresponds to an ICC that has a statistically significant positive correlation with transmission severity; a green bar corresponds to an ICC that has a statistically significant negative correlation; and a blue bar corresponds to an ICC that is not statistically significant. A statistically significant positive correlation of ICC with transmission outage severity would indicate a higher likelihood that an event with this ICC will result in a higher transmission outage severity. A statistically significant negative correlation indicates the contrary; in this case, a lower transmission outage severity would be likely. If a correlation is not statistically significant, this implies that a positive or negative correlation was very likely observed by mere chance, and there is, in fact, no linear relationship between ICC and the transmission outage severity. The events with this ICC have the expected transmission severity similar to all other events from the database.

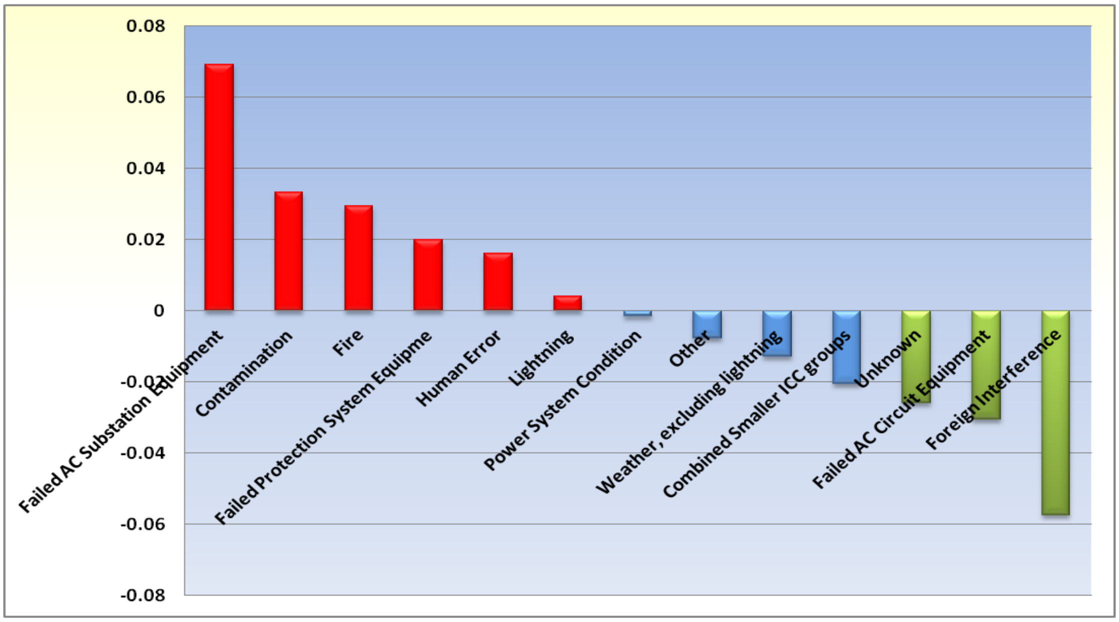

Figure 3.3: Correlation between ICC and TS of TADS Events (2009–2013)

Failed AC Substation Equipment is found to have the largest and most statistically significant positive correlation with 2009–2013 automatic transmission outage severity. In other words, 2009–2013 TADS events initiated by this cause tended to result in higher transmission severity than all other TADS events that occurred from 2009 to 2013.

Table 3.2 provides the transmission risk of each ICC as the product of the probability of the ICC event and its calculated transmission severity. The risk is then expressed as a percentage for each ICC relative to the other ICCs. As shown in Table 3.2, events related to weather represent the largest percentage of transmission severity. These are provided in two ICC groups in TADS: Lightning, and Weather Excluding Lightning. TADS events with an ICC of Lightning result in the greatest combined transmission severity for all TADS events. These Lightning events are typically momentary, single-mode outages and restore quickly, so therefore are not a significant impact to overall system reliability. Weather Excluding Lightning was found not to have a statistically significant correlation with transmission severity.

Table 3.2: Evaluation of ICC Relative Risk (2009–2013)

Group of TADS Events	Probability that an Event from a Group Starts during a Gven Hour	Expected Impact (Expected Transmission Severity of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group (%)
Lightning	0.092	0.164	0.015	21.3
Unknown	0.084	0.158	0.013	18.8
Weather Excluding Lightning	0.060	0.160	0.010	13.6
Human Error	0.034	0.169	0.006	8.0
Failed AC Substation Equipment	0.028	0.191	0.005	7.6
Failed AC Circuit Equipment	0.031	0.152	0.005	6.6
Failed Protection System	0.025	0.172	0.004	6.2
Contamination	0.016	0.182	0.003	4.0
Foreign Interference	0.020	0.136	0.003	3.9
Fire	0.011	0.183	0.002	2.8
Power System Condition	0.011	0.163	0.002	2.6
Other	0.010	0.158	0.002	2.3
Combined Smaller ICC groups	0.006	0.144	0.001	1.2
All TADS Events	**0.430**	**0.165**	**0.071**	**100.0**
All with ICC Assigned	**0.428**	**0.164**	**0.070**	**98.8**

Among non-weather-related ICCs (excluding Unknown), Human Error and Failed AC Substation Equipment are the two largest contributors to transmission severity. These two are tracked through closely related adequate level of reliability (ALR) metrics. As shown in Figure 3.3, TADS events initiated by either of these two causes have statistically significant greater expected severity than TADS non-weather ICC events. This is because a single substation element (equipment) failure may lead to multiple line outages on lines emanating from the same substation bus or end point. Therefore, the ac substation equipment failure would have the potential to substantially impact multiple locations. Further investigation into the Human Error ICC has led to a revision of the ICC data summary in the *State of Reliability 2013* report. Starting in 2012, more granular code data is available, and the ICC data summaries were modified, or augmented, as described in the following section of this chapter.

Finally, a series of statistical tests determined that both the average transmission severity of an event and the total transmission severity of TADS events in 2013 were statistically significantly smaller than in any other year from 2009 to 2012. Details of the statistical analysis of annual changes for the entire database as well as by ICC are described in Appendix A.

2012–2013 Study with Augmented Event Types

TADS event type reporting was modified in 2012 to further distinguish normal clearing events from abnormal clearing events. Components of the Human Error ICC are subdivided by type codes, which first became available in 2012. For the purpose of the report, two specific components related to protection system misoperation have been removed from the Human Error ICC and added to the ICC for Failed Protection System Equipment. This augmented ICC is labeled "Misoperation." To introduce the additional data into this study where this level of detail is not available for prior years, TADS events with protection system misoperations—event types 61 dependability[50] (failure to operate) and 62 security[51] (unintended operation)—are used to modify (or augment) ICCs as shown in Table 3.3. The new Misoperation ICC is analogous to protection system misoperations, which are comprised of Failed Protection System Equipment (FPSE) and Human Error (HE) with event type 61 or 62 (HE and Type 61/62). Aggregate totals of 2012–2013 TADS events by augmented ICC are provided in Table 3.3. Events initiated by Misoperations comprise 8.2 percent of all TADS events and represent the fourth-largest group of events (after weather-related and Unknown ICCs.) Chapter 3's transmission analysis covers the most recent five-year period. After three more years of data collection, the augmented ICC data collection method will have a full five years of data and will become the method used for studying the TADS event data.

Table 3.3: TADS Outage Events by Augmented ICC (2012–2013)

Initiating Cause Code	2012	2013	2012–2013
Lightning	852	813	1665
Unknown	710	712	1422
Weather Excluding Lightning	446	433	879
Misoperation: FPSE OR (HE AND Type 61/62)	321	281	602
Failed AC Circuit Equipment	261	248	509
Failed AC Substation Equipment	248	191	439
Human Error AND NOT (Type 61 OR Type 62)	212	191	403
Foreign Interference	170	181	351
Contamination	160	151	311
Fire	106	130	236
Power System Condition	77	109	186
Other	104	64	168
Vegetation	43	36	79
Vandalism, Terrorism, or Malicious Acts	10	9	19
Environmental	4	8	12
All with ICC Assigned	**3724**	**3557**	**7281**
In TADS	**3753**	**3557**	**7310**

[50] Event Type 61 Dependability (failure to operate): one or more automatic outages with delayed fault clearing due to failure of a single protection system (primary or secondary backup) under either of these conditions:

- Failure to initiate the isolation of a faulted power system Element as designed, or within its designed operating time, or
- In the absence of a fault, failure to operate as intended within its designed operating time.

[51] Event Type 62 Security (unintended operation): one or more automatic outages caused by improper operation (e.g., overtrip) of a protection system resulting in isolating one or more TADS elements it is not intended to isolate, either during a fault or in the absence of a fault.

Figure 3.4 shows the correlation between calculated transmission severity and each ICC in the same format as Figure 3.3. Using this augmented ICC data, Failed AC Substation Equipment and Misoperations had the largest and most statistically significant positive correlation with 2012–2013 ATO severity. In other words, TADS events initiated by these two causes tended to have higher transmission severity than other TADS events that occurred in 2012 and 2013. Power System Condition is the only other ICC with a statistically significant correlation to transmission severity, but the correlation is much smaller than Failed AC Substation Equipment and Misoperations. Therefore, the remaining discussion won't focus on TADS data from 2012 and 2013.

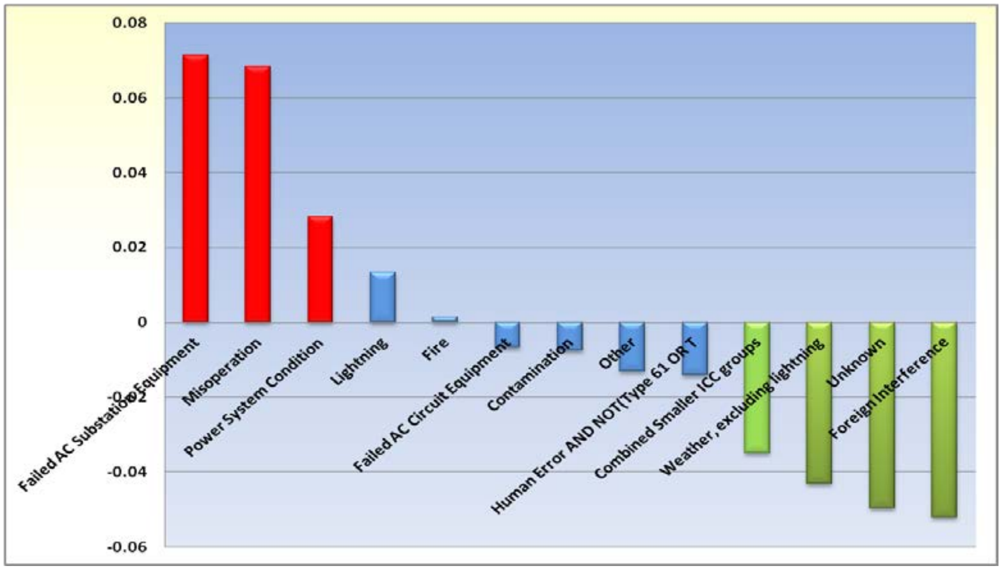

Figure 3.4: Correlation between Augmented ICC and TS of TADS Events (2012–2013)

Relative risk of the 2012–2013 TADS events by augmented ICC is listed in Table 3.4. The probability that an event from a given group initiated during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. Excluding weather-related and Unknown events, events initiated by Misoperations and by Failed AC Substation Equipment had the largest shares in the total transmission severity and contributed 9.4 and 7.1 percent, respectively, to transmission severity relative risk.

Table 3.4: Relative Risk by Augmented ICC (2012–2013)

Group of TADS Events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected Transmission Severity of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group (%)
Lightning	0.095	0.155	0.015	**23.1**
Unknown	0.081	0.143	0.012	**18.2**
Weather Excluding Lightning	0.050	0.143	0.007	**11.2**
Misoperation	0.034	0.175	0.006	**9.4**
Failed AC Substation Equipment	0.025	0.180	0.005	**7.1**
Failed AC Circuit Equipment	0.029	0.151	0.004	**6.9**
Human Error AND NOT(Type 61 OR Type 62)	0.023	0.150	0.003	**5.4**
Contamination	0.018	0.149	0.003	**4.2**
Foreign Interference	0.020	0.130	0.003	**4.1**
Fire	0.013	0.154	0.002	**3.2**
Power System Condition	0.011	0.170	0.002	**2.8**
Other	0.010	0.145	0.001	**2.2**
Combined Smaller ICC groups	**0.006**	**0.126**	**0.001**	**1.2**
All TADS Events	**0.417**	**0.153**	**0.064**	**100.0**
All with ICC Assigned	**0.415**	**0.152**	**0.063**	**99.1**

Focusing the statistical analysis of the 2012–2013 TADS augmented ICC data on the transmission severity and initiating causes of TADS events, and aligning that information with misoperations, yields the following results and observations:

- After excluding weather-related and Unknown ICCs, Misoperations and Failed AC Substation Equipment are the two largest contributors to the transmission severity risk.
- TADS events initiated by either of these ICCs have greater severity than all other TADS events.
- Among other ICCs, only Power System Condition[52] has a statistically significant positive correlation with transmission severity, but events initiated by this cause are infrequent and together contribute only 2.8 percent to the total transmission severity of the 2012–2013 TADS.

Common/Dependent Mode Event ICC Study (2009–2013)

TADS data also provides information to classify outages as single-mode or common or dependent mode (CDM) events that should be evaluated separately from single-mode events. CDM events result in multiple transmission element outages. It is important to monitor and understand CDM events due to their potential risk to system reliability.

Table 3.5 lists CDM events by ICC in the 2009–2013 database and their percentages with respect to all TADS events with a given ICC. Similar to all TADS events, Lightning initiated the largest number of CDM events. CDM events initiated by Failed AC Substation Equipment comprise the second largest group, followed by Weather Excluding Lightning and Human Error. Overall, 3,227 CDM events were defined, representing 17.1 percent of all TADS events from 2009 to 2013. Out of these, 3,136 are assigned to one of the 17 ICCs.

Table 3.5: CDM Events and Hourly Event Probability by ICC (2009–2013)

Initiating Cause Code	ALL TADS Events	CDM Events	CDM as % of ALL	Event Probability/Hour
Reliability Metrics	**5167**	**1249**	**24.2**	**0.0285**
Failed AC Substation Equipment	1233	444	36.0	0.0101
Failed Protection System Equipment	1111	296	26.6	0.0068
Human Error	1474	324	22.0	0.0074
Failed AC Circuit Equipment	1349	185	13.7	0.0042
Lightning	4018	559	13.9	0.0128
Weather Excluding Lightning	2626	334	12.7	0.0076
Unknown	3698	306	8.3	0.0070
Power System Condition	493	310	62.9	0.0071
Other	450	109	24.2	0.0025
Foreign Interference	893	97	10.9	0.0022
Fire	475	77	16.2	0.0018
Contamination	685	59	8.6	0.0013
Combined Smaller ICC groups	**249**	**36**	**14.5**	**0.0008**
Vegetation	179	14	7.8	0.0003
Environmental	33	11	33.3	0.0003
Failed AC/DC Terminal Equipment	3	3	100.0	0.0001
Vandalism, Terrorism, or Malicious Acts	34	8	23.5	0.0002
All In TADS	**18866**	**3227**	**17.1**	**0.0736**
All with ICC Assigned	**18754**	**3136**	**16.7**	**0.0716**

[52] Defined as "Automatic Outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out of service)."

Almost all ICC groups of CDM events for five years have a sufficient sample size to be used in a statistical analysis, but the sample size is not enough to track statistically significant year-over-year changes in transmission severity. Four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental, Failed AC/DC Terminal Equipment) must be combined to comprise a new group, Combined Smaller ICC Groups, that can be statistically compared to every other group.

Figure 3.5 shows the correlation between calculated transmission severity and each ICC in the same format as Figure 3.3.

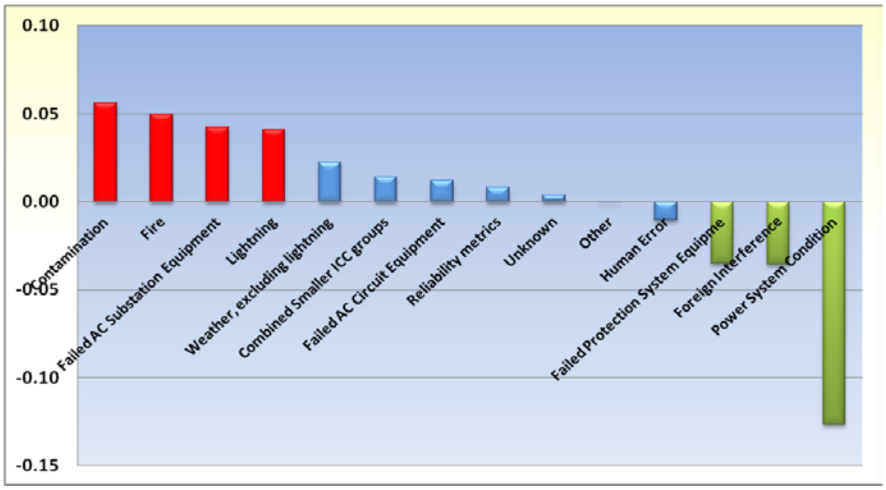

Figure 3.5: Correlation between ICC and TS of TADS CDM Events (2009–2013)

CDM events are a subset of the previously evaluated TADS events. Table 3.6 provides a breakdown of relative risk of CDM events by ICC.

Table 3.6: Evaluation of CDM Event ICC Contribution to Transmission Severity (2009–2013)

Group of TADS Events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected Transmission severity of an event)	Risk Associated with a Group Per Hour	Relative Risk by Group (%)
CDM Lightning	0.013	0.258	0.003	4.6
CDM Failed AC Substation Equipment	0.010	0.261	0.003	3.7
CDM Weather Excluding Lightning	0.008	0.253	0.002	2.7
CDM Human Error	0.007	0.236	0.002	2.5
CDM Unknown	0.007	0.244	0.002	2.4
CDM Failed Protection System Equipment	0.007	0.221	0.001	2.1
CDM Power System Condition	0.007	0.170	0.001	1.7
CDM Failed AC Circuit Equipment	0.004	0.250	0.001	1.5
CDM Other	0.002	0.241	0.001	0.8
CDM Fire	0.002	0.300	0.001	0.7
CDM Foreign Interference	0.002	0.204	0.000	0.6
CDM Contamination	0.001	0.317	0.000	0.6
CDM Combined Smaller ICC groups	0.001	0.257	0.000	0.3
All TADS Events	**0.430**	**0.165**	**0.071**	**100.0**
All CDM Events	**0.074**	**0.244**	**0.018**	**25.4**
All with ICC assigned	**0.072**	**0.241**	**0.017**	**24.4**

Analysis of the TADS CDM events indicated that events with ICCs of Failed AC Substation Equipment and Human Error are the two largest contributors to transmission severity with the exception of weather-related events. CDM events initiated by Failed AC Substation Equipment have statistically greater expected severity than other CDM events; however, the difference in transmission severity of CDM events initiated by Human Error and all other CDM events is not statistically significant. In other words, CDM events initiated by Human Error on average have the same transmission severity as all the other CDM events that occurred between 2009 and 2013.

Summary of Analysis

Figure 3.6 represents an analysis of the risk profile of the 2009–2013 TADS events combined study. The horizontal axis is the magnitude of the correlation of a given ICC with transmission severity. The vertical axis represents the expected transmission severity of an event when it occurs. The color of the marker indicates if there is a correlation of transmission severity with the given ICC (either positive - Red, negative - Green, or no significant correlation- Blue). The size of the marker indicates the probability of an event initiating in any hour with a given ICC. Failed AC Substation Equipment shows a statistically significant positive correlation of transmission severity and a higher relative transmission risk based on the probability of a failure initiating in any hour and the expected transmission severity when it occurs. Human error and failed protection system equipment both show a statistically significant positive correlation of transmission severity but individually show a moderately higher relative transmission risk. Fire, while showing a positive correlation of transmission severity, has a low relative transmission risk.

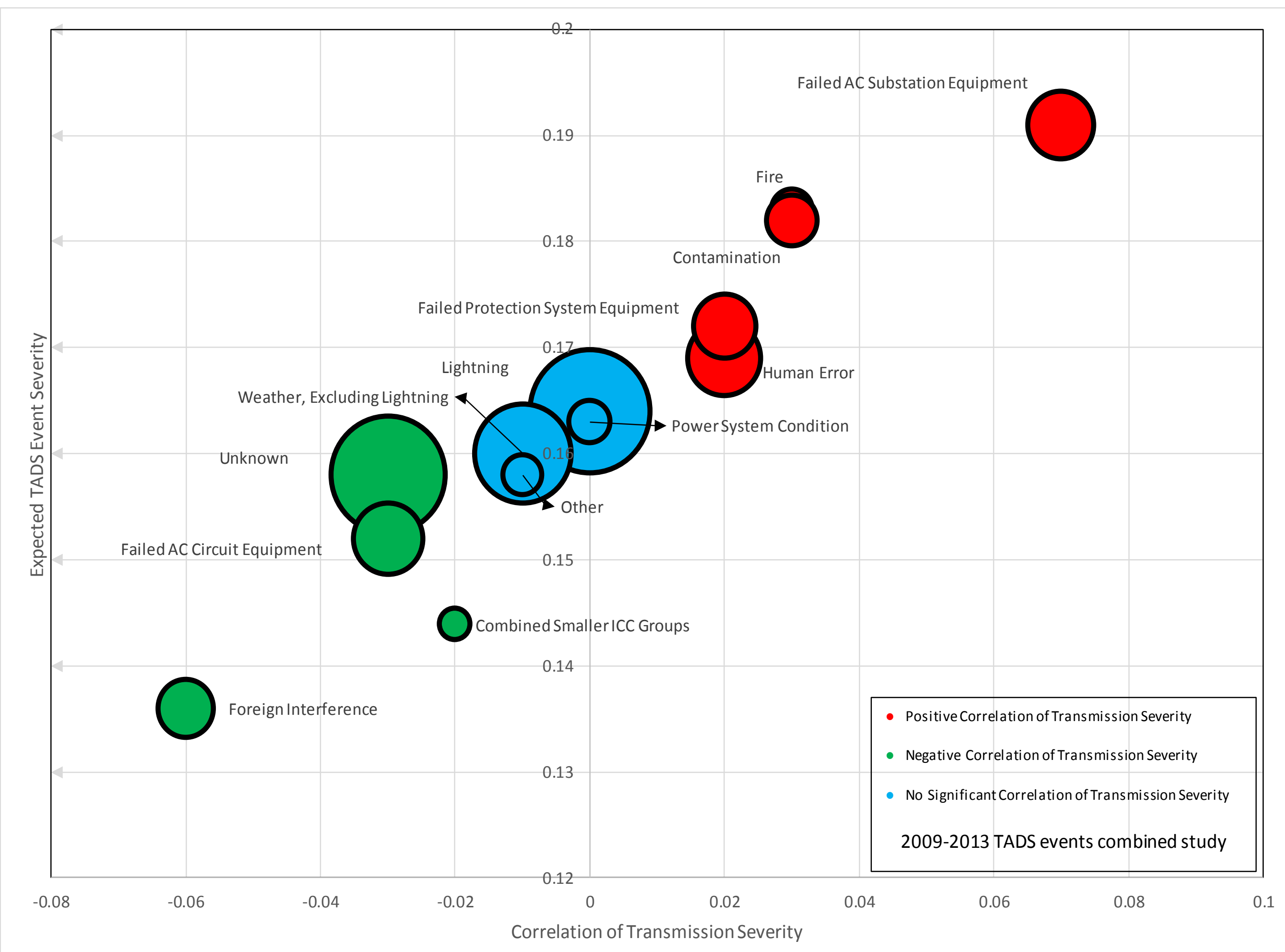

Figure 3.6: Risk Profile of the 2009–2013 TADS Events Combined Study

Figure 3.7 represents an analysis of the risk profile of the 2012–2013 study with augmented event types (augmented to further distinguish normal clearing events from abnormal clearing events). The parameters for the chart remain the same as in Figure 3.6. With the introduction of the Misoperation ICC (which combines Failed Protection System Equipment and Human Error associated with Misoperations), Failed AC Substation Equipment and Misoperations both show a statistically significant positive correlation with transmission severity and show a higher relative transmission risk. Power System Condition, while showing a positive correlation of transmission severity, has a lower relative transmission risk, based on the probability of this TADS event initiating in any hour and its expected transmission severity. On the other end of the risk spectrum, Lightning shows a high relative transmission risk but has no significant correlation with transmission severity.

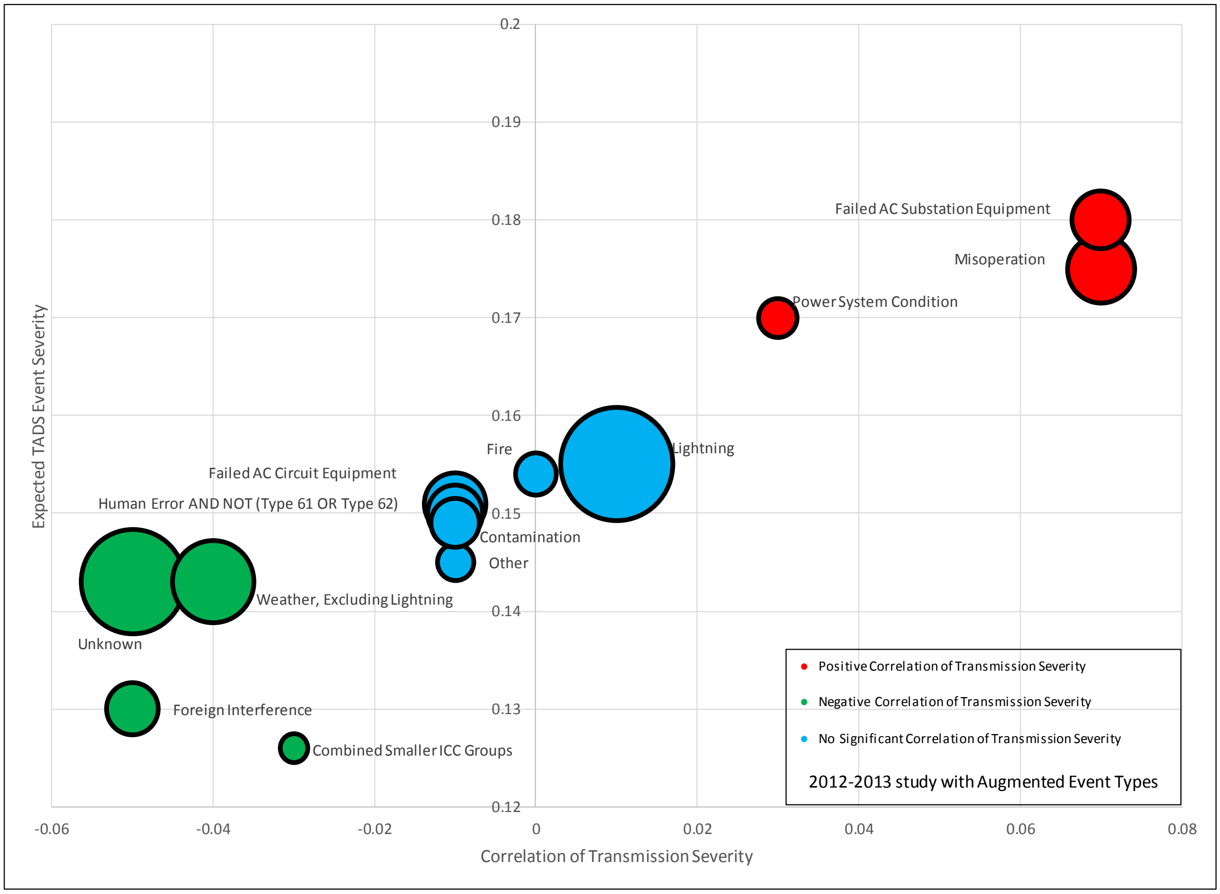

Figure 3.7: Risk Profile of the 2012–2013 TADS Events by Augmented ICC

Figure 3.8 represents an analysis of the risk profile of the 2009–2013 Common/Dependent Mode Event ICC Study. The parameters for the chart remain the same as in Figure 3.6 and Figure 3.7. Failed AC Substation Equipment and Lightning both show a statistically significant positive correlation with transmission severity and show a higher relative transmission risk. On the other end of the risk spectrum, Weather Excluding Lightning shows a high relative transmission risk but has no significant correlation with transmission severity.

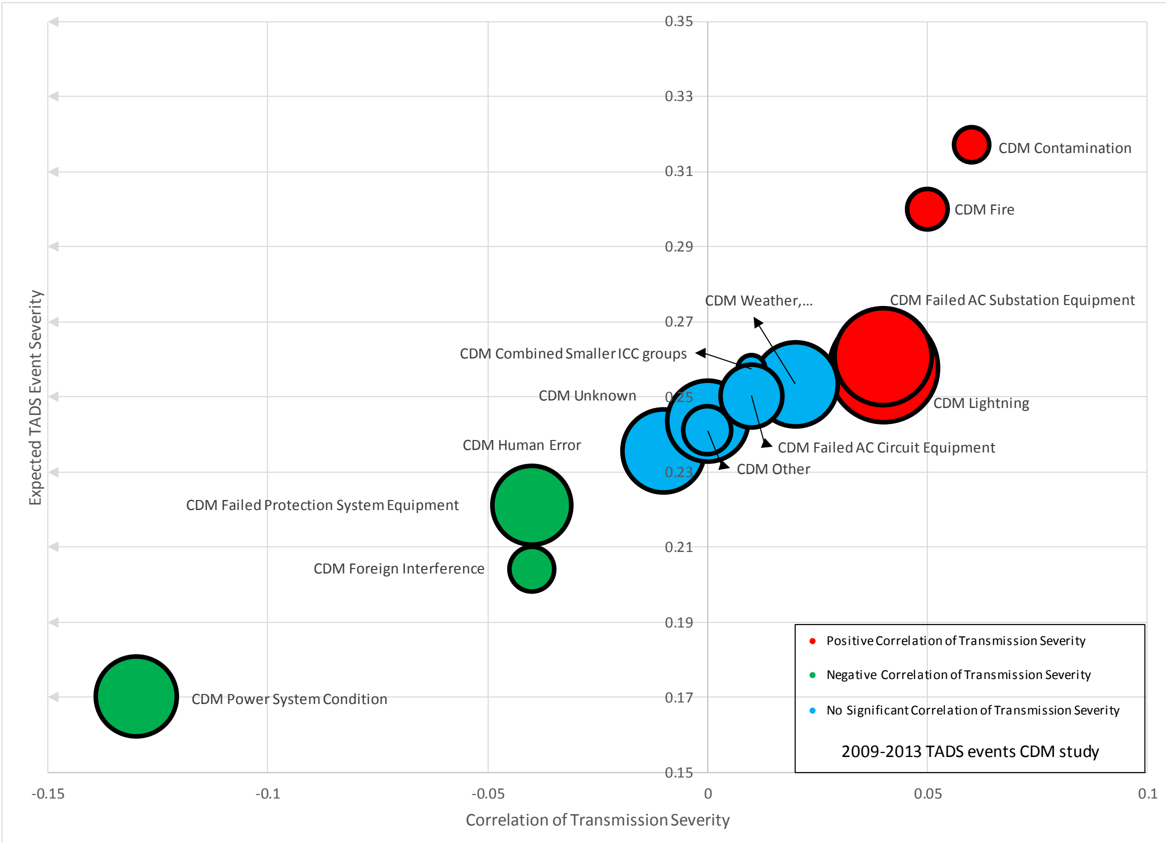

Figure 3.8: Risk Profile of the 2009–2013 Common/Dependent Mode Event ICC Study

Focusing the statistical analysis of the 2012–2013 TADS data on the transmission severity and initiating causes of TADS events and aligning that information with misoperations yields the following results and observations:

- After excluding weather-related and Unknown ICCs, Misoperations and Failed AC Substation Equipment are the two largest contributors to transmission severity risk.
- TADS events initiated by either of these ICCs have statistically significant greater expected severity than all other TADS events.
- Among other ICCs, only Power System Condition has a statistically significant positive correlation with transmission severity, but events initiated by this cause are less frequent and together contribute only 2.8 percent to the total transmission severity of the 2012–2013 TADS.
- Statistical tests resulted in the conclusion that both the average transmission severity of the events initiated by Misoperations and their total transmission severity significantly decreased in 2013 versus 2012.
- Based on the five-year statistical analysis, the average and total transmission severity and the relative transmission risk of Failed AC Substation Equipment significantly decreased in 2013, compared with 2011 and 2012.

Chapter 4 – Reliability Indicator Trends

Reliability Indicator Trends – Summary

NERC reliability indicators are intended to tie the actual performance of the BES to the set of specified objectives and outcomes for the NERC reliability objectives to measure whether an adequate level of reliability exists. Based on the events that occurred in 2013 and the metrics data analyzed, the system shows a continuing trend toward maintaining reliability. In other words, the system experienced a wide range of operating conditions and the BES operated as planned and designed.

One of the stated purposes for the new ALR definition is for the NERC PAS to assess BES reliability and identify gaps in data collection. In 2013, the PAS focused on aligning the existing ALR reliability indicators with the new ALR definition.[53] Table 4.1 shows the mapping of the 16 metrics monitored in 2013 to the seven reliability performance objectives of the new ALR definition. With the revised ALR definition that was approved in 2012, the existing metric naming convention no longer maps well to the objectives in the ALR definition. Therefore, the PAS is recommending a new naming convention for the existing 16 metrics, shown in parentheses below.

Table 4.1 Adequate Level of Reliability Metrics

Reliability Performance Objectives	System Stability	System Frequency	System Voltage	Manage Contingencies	Coordinate Restoration	Transmission Adequacy	Resource Adequacy
ALR Metrics (New ID)	ALR1-4 (M-2) ALR1-12 (M-4) ALR4-1 (M-9)	ALR1-12 (M-4) ALR2-4 (M-6)	ALR1-5 (M-3)	ALR1-4 (M-2) ALR2-3 (M-5) ALR2-4 (M-6) ALR2-5 (M-7) ALR3-5 (M-8) ALR6-2 (M-11)	ALR1-4 (M-2) ALR2-3 (M-5) ALR6-2 (M-11)	ALR1-4 (M-2) ALR3-5 (M-8) ALR6-1 (M-10) ALR6-11 (M-12) ALR6-12 (M-13) ALR6-13 (M-14) ALR6-14 (M-15) ALR6-15 (M-16)	ALR1-3 (M-1) ALR6-2 (M-11)

These metrics exist within a reliability framework. The existing 16 performance metrics align with the performance objectives for the design, planning, and operation of the BES. These metrics contribute to the reliability performance objectives, which will lead to a more resilient and reliable BES. There is at least one existing performance metric associated with each of the performance objectives listed in the table.

The definition of ALR speaks to the state of the BES in which the performance objectives are met. It is therefore intuitive that one could not base such an assessment of reliability on one metric only; rather, it is necessary to look at the entire set of metrics to evaluate that the ALR state has been attained. Any comparisons of individual metrics alone or between regions should therefore be evaluated with care.

Another metric reporting principle is to retain anonymity of individual reporting organizations. Thus, details are presented in this report at a NERC level and a regional level and do not compromise anonymity of individual reporting organizations.

Process Overview

Building upon previous metric reviews, the results of the approved performance metrics continue to be assessed. Each metric is designed to provide a measure of one or more performance objectives.

[53] http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Informational_Filing_Definition_Adequate_Level_Reliability_20130510.pdf

Due to varying data availability, each of the performance metrics does not address the same time period (some metrics have just been established or modified, while others represent data collected over many years). At this time, the number of metrics is expected to remain relatively stable; however, the PAS annually reviews them. Working with industry subject matter experts, the RAS may recommend changes to metrics, or new metrics, as gaps are identified in reliability data. In 2013, such a review was performed that resulted in the retirement of two existing metrics and the modification of several others. Specific changes to metrics that were approved in 2013 and early 2014 will be described in greater detail further in this section.

Table 4.2 provides an overview of the ALR metric trends through 2013. Although a number of performance categories have been assessed, some do not yet have sufficient data to derive conclusions from the metric results. Assessment of these metrics should continue as additional data becomes available to determine if the metric is a good indicator of the performance objective it is meant to measure.

	Table 4.2: Metric Trend Ratings	
ALR	System Stability	**Trend Rating**
ALR1-4 (M-2)	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	◑
ALR1-12 (M-4)	Interconnection Frequency Response	◑*
ALR4-1(M-9)	Automatic Transmission Outages Caused by Failed Protection System Equipment (modified in 2013)	◑*
	System Frequency	
ALR1-12 (M-4)	Interconnection Frequency Response	◑*
ALR2-4 (M-6)	Average Percent Non-Recovery Disturbance Control Standard Events	◑*
	System Voltage	
ALR1-5 (M-3)	System Voltage Performance	◑***
	Manage Contingencies	
ALR1-4 (M-2)	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	◑
ALR2-3 (M-5)	Activation of Underfrequency Load Shedding	◑**
ALR2-4 (M-6)	Average Percent Non-Recovery Disturbance Control Standard Events	◑*
ALR2-5 (M-7)	Disturbance Control Events Greater than Most Severe Single Contingency	◑*
ALR3-5 (M-8)	Interconnected Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances (modified in 2013)	◑*
ALR6-2 (M-11)	Energy Emergency Alerts (modified in 2013)	●
	Coordinate Restoration	
ALR1-4 (M-2)	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	◑
ALR2-3 (M-5)	Activation of Underfrequency Load Shedding	◑**
ALR6-2 (M-11)	Energy Emergency Alerts (modified in 2013)	●
	Transmission Adequacy	
ALR1-4 (M-2)	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	◑
ALR3-5 (M-8)	Interconnected Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances (modified in 2013)	◑*
ALR6-1 (M-10)	Transmission Constraint Mitigation	◑**
ALR6-11 (M-12)	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	◑*

ALR6-12 (M-13)	Automatic AC Transmission Outages Initiated by Human Error	◑*
ALR6-13 (M-14)	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	◑*
ALR6-14 (M-15)	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	◑*
ALR6-15 (M-16)	Element Availability Percentage (modified and combined with 6-16 in 2013)	◑*
	Resource Adequacy	
ALR1-3 (M-1)	Planning Reserve Margin	◑*
ALR6-2 (M-11)	Energy Emergency Alerts (modified in 2013)	●

Trend Rating Symbols	
Significant Improvement	●
Slight Improvement	◕
No Change	◑
Inconclusive/Mixed	◑*
Slight Deterioration	◔
Significant Deterioration ⚠ ⚠	○
New Data	◑***
Incomplete Dataset/not enough to draw any conclusion	◑**

This chapter provides a discussion of the ALR metric trend ratings and activity on certain metrics where some changes have been implemented and which are associated to some key findings and conclusions. The full set of metrics and their descriptions, along with the results and trending, are on the NERC public website.[54]

ALR1-4 (M-2) BPS Transmission-Related Events Resulting in Loss of Load

Background

This metric measures BPS transmission-related events resulting in the loss of load, excluding weather-related outages. Planners and operators can use this metric to validate their design and operating criteria by identifying the number of instances when loss of load occurs. For the purposes of this metric and to be consistent with the revised metric approved by the OC and PC in March 2014, an "event" is an unplanned disturbance that produces an abnormal system condition due to equipment failures or system operational actions (either intentional or unintentional) that result in the loss of firm system demands. The metric analysis uses the subset of data provided by entities as specified in EOP-004-2. The reporting criteria for such events beginning with data for 2013 are outlined below:[55]

1. Loss of firm load for 15 minutes or more:

   a. 300 MW or more for entities with previous year's demand of 3,000 MW or more.

   b. 200 MW or more for all other entities.

2. BES Emergency requiring manual firm load shedding of 100 MW or more.
3. BES Emergency resulting in automatic firm load shedding of 100 MW or more (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS).

[54] Assessments & Trends: Reliability Indicator, http://www.nerc.com/pa/RAPA/Pages/ReliabilityIndicators.aspx
[55] http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf

4. Transmission loss event with an unexpected loss within an entity's area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing) resulting in a firm load loss of 50 MW or more.

This metric was reviewed in 2013, and changes were made to make the criteria more consistent with the approved changes to EOP-004-2 reporting criteria that pertain to transmission-related events that result in loss of load. The criteria presented above were approved for implementation in the first quarter of 2014. Changes in the annual measurement between 2012 and 2013 therefore reflect the addition of the new criteria applied to the 2013 data.

Assessment

Figure 4.1 shows that the number of BPS transmission-related events resulting in loss of firm load from 2002 to 2011 is relatively constant. The year 2012 was better in terms of transmission-related load loss events, with only two events having resulted in total load loss of 1,055 MW. There were fewer events in 2013 than prior years, with the exception of 2007 and 2012. On average, eight to 10 events were experienced per year. The top-three years in terms of load loss are 2003, 2008, and 2011, as shown in Figure 4.2. In 2003 and 2011, one event accounted for over two-thirds of the total load loss, while in 2008, a single event accounted for over one-third of the total load loss. In 2013, there was a lower-than-average level of load lost in megawatt-hours with total load loss less than all previous years studied except for 2012.

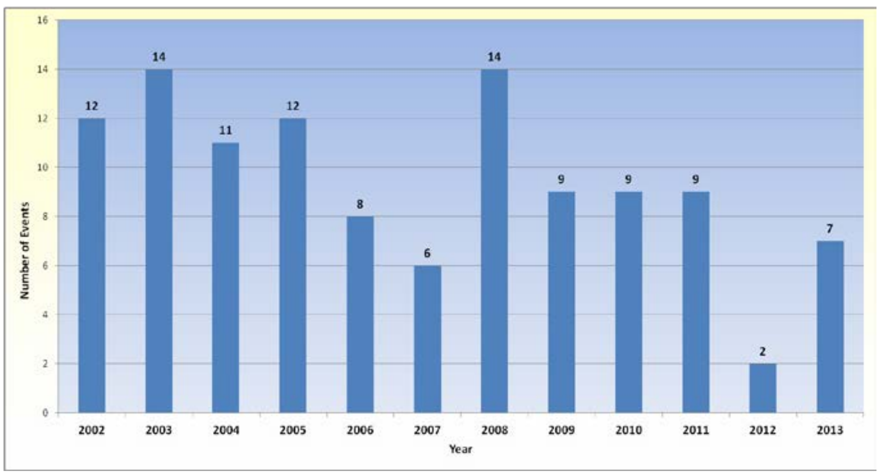

Figure 4.1: ALR1-4 BPS Transmission-Related Events Resulting in Load Loss (2002–2013)

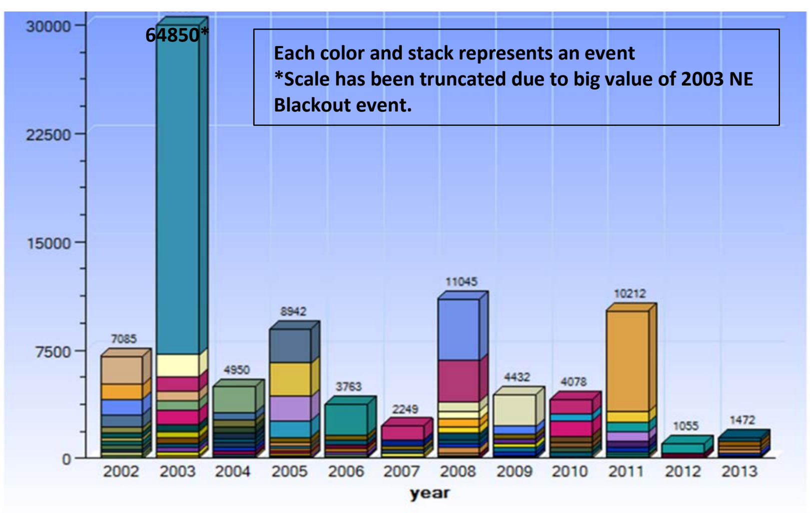

Figure 4.2: ALR1-4 BPS Transmission-Related Events Resulting in Load Loss (2002–2013)

Figure 4.3 is a new addition to this metric; it shows total megawatt loss values and duration of events resulting in firm load loss of 50 MW or greater. So, this figure shows that in addition to the seven events reported under the previous criteria, there are an additional seven events that were associated with the new criteria indicate events with load loss less than 100 MW and greater than or equal to 50 MW which is a new addition to the ALR1-4 Metric. So, while Figure 4.1 and 4.2 show 2013 transmission-related load-loss events based on the historical metric language, Figure 4.3 provides magnitude and duration of megawatt load loss for transmission-related load-loss events in 2013. It includes the new criteria in the metric to capture transmission-loss events with an unexpected loss in an entity's area of three or more BES elements (contrary to design) caused by a common disturbance (excluding successful automatic reclosing) that results in a firm load loss of 50 MW or more. Further analysis and continued assessment of the trends over time will continue in future years.

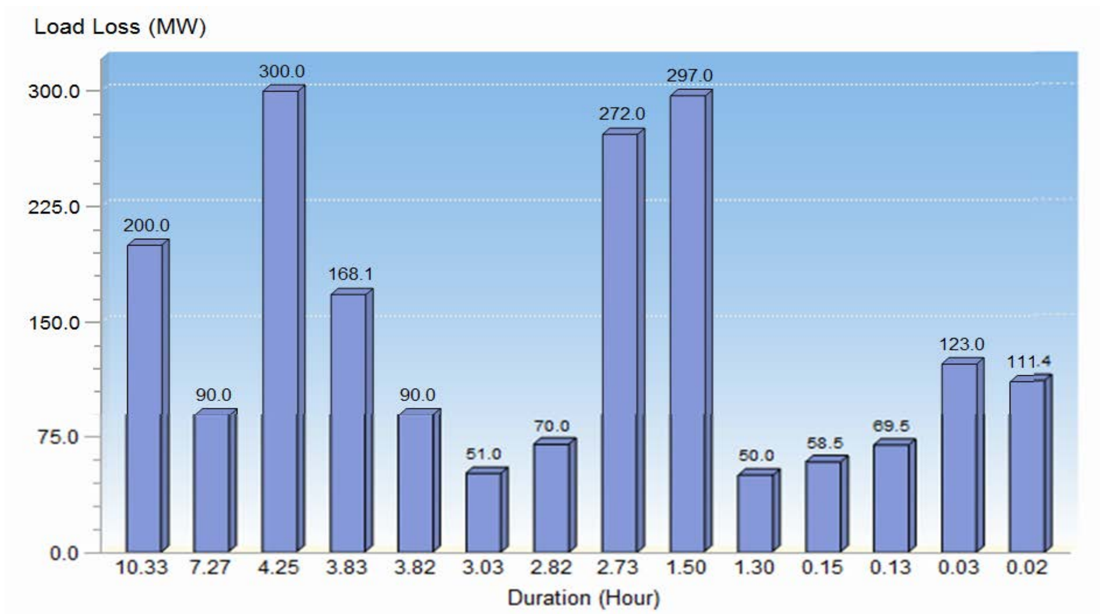

Figure 4.3: ALR1-4: 2013 Events with Load Loss ≥ 50 MW

Special Considerations

The collected data does not indicate whether load loss during an event occurred as designed or not as designed. Going forward, NERC will continue to refine data collection for this metric to allow grouping the data into categories such as separating load loss as designed versus unexpected firm load loss. NERC should support differentiating between load loss as a direct consequence of an outage and load loss as a result of operator-controlled action to mitigate an IROL/SOL exceedance.

ALR1-12 Metric Interconnection Frequency Response

Background

This metric is used to track and monitor interconnection frequency response. Frequency response is a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. It is a critical component to the reliable operation of the BPS, particularly during disturbances. The metric measures the average frequency response for all events where frequency deviates more than the interconnection's defined threshold, as shown in Table 4.3.

The following are frequency response calculations of the Eastern Interconnection, Western Interconnection, ERCOT Interconnection, and Québec Interconnection. The frequency response should not be compared within interconnections, because their BPS characteristics differ significantly in terms of number of facilities, miles of line, operating principles, and simple physical, geographic, and climatic conditions.

Table 4.3: Frequency Event Triggers

Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	36 or Point C below 59.960 Hz and delta Hz more than 30 mHz within 15 second time window	800	15
Western	70	700	15
ERCOT	90 or Point C below 59.900 Hz or above 60.100 Hz	450	15
Québec	350	450	15

Figure 4.4 shows the criteria for calculating average values A and B used to report frequency response. The event starts at time t±0. Value A is the average from t-16 to t-2 seconds, and Value B is the average from t+20 to t+52 seconds. The difference of value A and B is the change in frequency[56] used for calculating frequency response. The monthly frequency event candidate lists are posted on the NERC Resources Subcommittee[57] website. These lists are vetted by the NERC Frequency Working Group and the final list is published on a quarterly basis. The data is used to support the frequency response standard BAL-003 – Frequency Response and Bias. The frequency event data collection process is described in the BAL-003 Frequency Response Standard Supporting Document.[58]

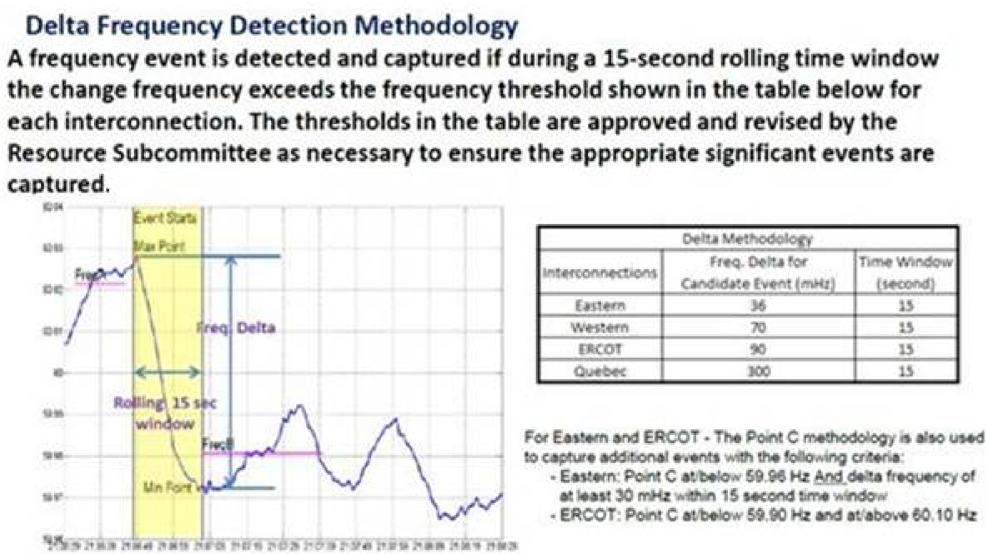

Figure 4.4: Criteria for Calculating Value A and Value B

The actual megawatt loss for the frequency event is determined jointly by NERC and Regional Entity situation awareness staff to develop the monthly frequency event candidate list. Both the change in frequency and the megawatt loss determine whether the event qualifies for further consideration for use in the ALR 1-12 metric or for the measurement of BA performance under Standard BAL-003 – Frequency Response and Bias by the NERC Frequency Working Group. If the event qualifies, then the actual megawatt loss is converted to a beta value (MW/.1 Hz) for use in Figure 4.4 above. The final monthly datasets of approved frequency events[59] are then used to analyze the interconnection frequency response performance.

56 ALR1-12 Frequency Response Data Collections Process, Slide 18 of Presentation 1, 10/26-27/2011 http://www.nerc.com/docs/oc/rs/RS_Presentation_October_2011.pdf

57 Resource Subcommittee (RS), http://www.nerc.com/comm/OC/Pages/Resources-Subcommittee-(RS)-2013.aspx

58 BAL-003-1 Frequency Response & Frequency Bias Setting Standard, 07/18/2011, http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/NOPR_Proposal for BAL-003-1.pdf

59 Starting in 2014, all frequency events selected for use in BAL-003 shall be also used for the ALR 1-12 frequency performance metric.

Table 4.4 shows the number of frequency events per year for each interconnection from 2009 through 2013. The increase in the number of events for the Eastern Interconnection in 2013 is because of the new threshold, which is 36 mHz, or Point C below 59.960 Hz and delta Hz more than 30 mHz within a 15-second time window.

Table 4.4: Yearly Number of Frequency Events

Interconnection	2009	2010	2011	2012	2013
Western	25	29	25	12	28
Eastern	44	49	65	28	71
ERCOT	51	67	65	63	52
Québec	-	-	20	28	37

Care is taken to select events that impact the frequency beyond the expected dead-band settings for that interconnection. Beta megawatt projections for events that are just slightly larger than the interconnection megawatt cutoff threshold can potentially result in outliers. The resulting frequency response for these smaller events may be quite minimal if generator governors have dead-bands set higher than the expected value. Another factor that can impact the projected beta megawatt value is the 32 second average value chosen for point B. If the frequency response is not sustained for the duration of the 32 second average, the resulting frequency response will be lower and consequently result in a lower beta megawatt value. Lack of sustained frequency response is evident in the Eastern Interconnection and is referred to as the "Lazy L" in frequency/time charts.

Assessment

NERC annually applies statistical tests to interconnection frequency response datasets,[60] and additional analyses on time of year, load levels, and other attributes were conducted in 2013. Frequency response is the ratio of the megawatts lost when generation is tripped and the difference in frequency before and after the event. A large value of frequency response is considered better than a small value.

Frequency Response Trending

From 2009 through 2013, the historical frequency response shows the following trends:

- The Eastern Interconnection has shown steady frequency response performance. A decreasing but not statistically significant time trend for frequency response was observed (there is a high probability the negative slope of the trend line occurred by pure chance). In 2013 the frequency response had the smallest average value observed over the five years studied; moreover, there was a statistically significant decrease of frequency response compared with 2011, which had the best frequency response performance over the same time period.
- The ERCOT Interconnection has had a statistically significant frequency response increase with the average monthly growth of 3.3 MW/0.1Hz; one of the contributing factors was the continued increase in wind generation in ERCOT that typically operates at maximum output. Without margin in the up direction, the interconnection only benefits by curtailing wind generators during high-frequency excursions from these generators. When low-frequency excursions occur, the wind generators cannot provide additional output to increase interconnection frequency.
- The Québec Interconnection (only for 2011–2013) has shown steady frequency response performance; and
- The Western Interconnection has shown steady frequency response performance.

[60] Datasets described in the Frequency Response Initiative Report, October 2012, http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Figure 4.5 uses a time-trend regression line to show year-to-year time trends by interconnection. The study methods and statistical results are summarized in Chapter 4 and Appendix B.

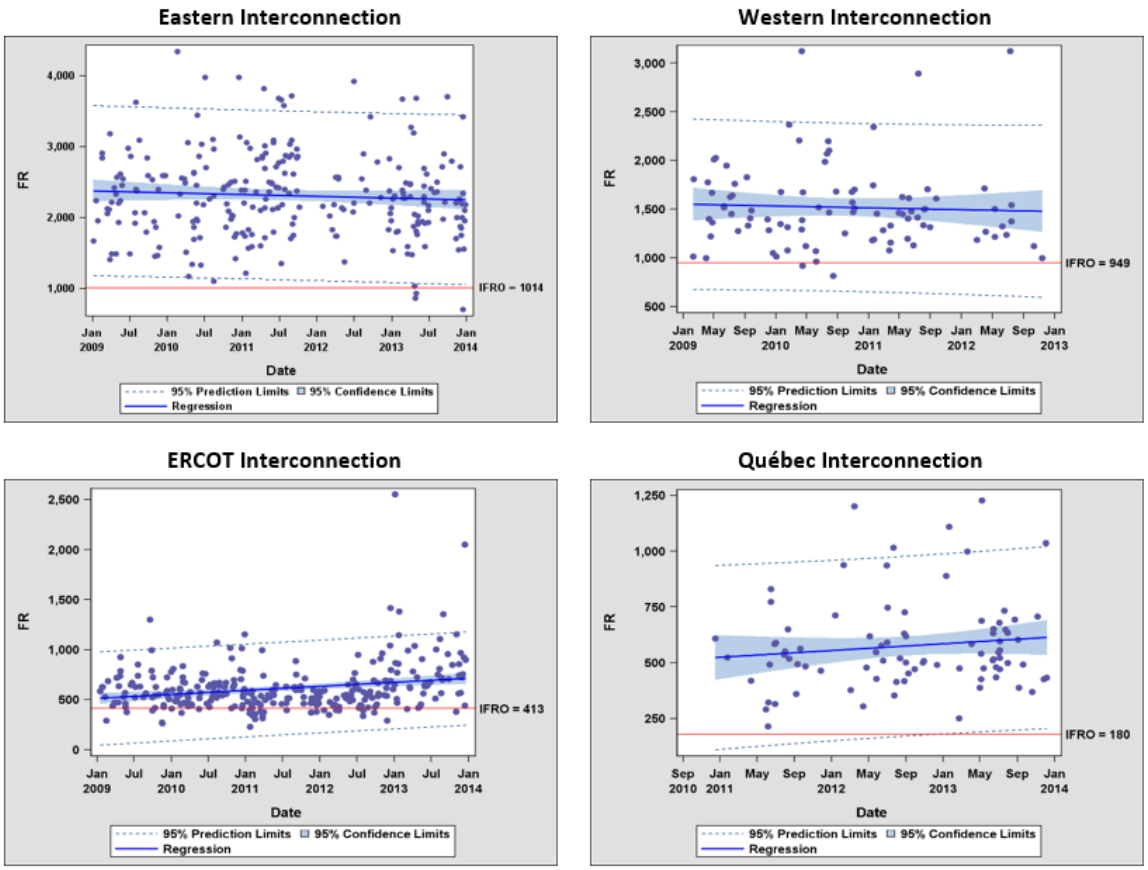

Figure 4.5 Interconnection Frequency Response Trend (2009–2013)

Relation to Interconnection Frequency Response Obligations

The expected frequency response for each interconnection was compared to its respective IFROs from the 2013 Frequency Response Annual Analysis. In all cases, the statistically expected frequency response for each interconnection has been higher than the recommended absolute values of IFRO.[61]

However, the historical frequency responses show (details in Appendix B):

- The Eastern Interconnection has had three events (1.2 percent of all Eastern Interconnection events) with the frequency response value below the absolute IFRO, all of which occurred in 2013;
- The ERCOT Interconnection has had 34 events (11.4 percent of all ERCOT events) with the frequency response value below the absolute IFRO, none of which occurred in 2013;
- The Québec Interconnection has had no events with the frequency response value below the absolute IFRO; and
- The Western Interconnection has had three events (2.5 percent of all Western Interconnection events) with the frequency response value below the absolute IFRO, none of which occurred in 2013.

[61] Current recommended IFRO values are presented in the Frequency Response Annual Analysis, December 2013, Annual Analysis, http://www.nerc.com/FilingsOrders/us/NERC Filings to FER DL/FR Annual Report 12-27-13 Final.pdf

Several factors contributed to the frequency response performance in ERCOT during the years the frequency response did not meet the recommended IFRO (2011 and 2012).

- ERCOT has a small hydro fleet that suffered significantly due to the extreme drought of 2011. There was some relief in 2012, but not in the geographical area of these hydro facilities. Additionally, the owners of the facilities have changed the facilities' operation. Prior to the ERCOT nodal market implementation in December 2010, many of these facilities were operated as frequency responsive reserves. They were on-line in synchronous condenser mode and ramped to full output in about 20 seconds anytime frequency dropped to 59.900 Hz or below, providing 50 to 240 MW of primary frequency response (during the first 20 seconds of a disturbance). Since early 2011, this service has been discontinued. The drought along the Colorado River that provides water to most of the hydro plants in Texas has not improved much. As of March 18, 2014, the watershed area for this river remains in extreme drought or severe drought conditions and has not recovered since 2011.

ERCOT's frequency response performance improved in 2013 for the following reasons:

- Natural gas prices have risen above coal and lignite prices, and solid fuel plants are again dispatched ahead of combined-cycle plants. However, the effort that began in September 2012 by the Texas Reliability Entity (TRE) has proven to be the major contributor to improved frequency response performance in ERCOT. The TRE has followed up with mitigation plans developed by generators of all fuel types to improve their frequency response. As these generators completed these efforts in 2013, the grid frequency response improved.
- FERC approved BAL-001-TRE-1 earlier this year, and the implementation phase began on April 1, 2014. This regional standard will help maintain the frequency response performance of generators in ERCOT and will standardize the dead-band settings of these generators. It is not yet known how much improvement in frequency response will result from this standard since many of the generators have already implemented the required settings. Some improvement in the RMS1 of frequency may be observed as more generators implement the lower governor dead-band settings.

Statistical significance tests have been applied to interconnection frequency response datasets, and additional analysis on time of year, load levels, and other attributes were also conducted. The overall observations and test results are summarized below:

- The Eastern Interconnection frequency response was stable from 2009 through 2013.[62]
- The ERCOT Interconnection frequency response grew from 2009 through 2013.[63]
- The Québec Interconnection[64] frequency response was stable from 2011 through 2013.[65]

[62] The correlation between time variable and frequency response is negative and this is equivalent to the fact that the slope is negative and the trend line is decreasing function. However, the correlation is not statistically significant. This leads to the failure to reject the null hypothesis of zero correlation. So even though the decreasing trend for frequency response in time was observed, there is a high probability that the negative correlation and the negative slope occurred by chance.

[63] The correlation between time variable and frequency response is positive, and this is equivalent to the fact that the slope is positive and the trend line is increasing function with the average monthly growth of 3.3 MW/Hz*0.1; moreover, the correlation is statistically significant (p<0.0001). This leads to the rejection of the null hypothesis of zero correlation. So, the observed increasing trend for frequency response is very unlikely occurred by chance.

[64] Only 2011–2013 data is available for Québec Interconnection.

[65] The correlation between time variable and frequency response is positive and this is equivalent to the fact that the slope is positive and the trend line is increasing function. However, the correlation is not statistically significant. This leads to the failure to reject the null hypothesis of zero correlation. So even though the increasing trend for frequency response in time was observed, there is a high probability that the positive correlation and the positive slope occurred by chance.

- The Western Interconnection frequency response was stable from 2009 through 2013.[66]

Special Considerations – Explanatory Variables

As recommended in the *2012 State of Reliability* report,[67] specific attributes have been further studied in order to understand their influence on the severity of frequency deviation events. For each interconnection, a set of six attributes was selected to be studied as explanatory variables for the interconnection frequency response. First, the correlation analysis was carried out to find statistically significant[68] contributors to frequency response; then, the explanatory variables were used as regressors in the multiple regression model that describes the interconnection frequency response. The model selection methods help identify important contributors and remove insignificant or highly correlated regressors to avoid redundancy. The following six specific attributes are included in the studies and tested for the frequency response data of each interconnection. The details of this analysis can be found in Appendix B.

- Summer
- Winter
- High Pre-Disturbance Frequency
- On-peak Hours
- Time
- Interconnection Load Level

For the Eastern Interconnection, only two variables (load level and high pre-disturbance frequency) have a statistically significant correlation with frequency response. The load level has the largest impact on frequency response, followed by the indicator of high pre-disturbance frequency. Interconnection load is positively correlated with frequency response, and high pre-disturbance frequency is negatively correlated with frequency response. There are a number of potential reasons why frequency response can improve as interconnection load level increases. Additional generators will typically be online at higher load periods. This can potentially increase the overall headroom of the generation that is online. It can also increase overall governor participation. In general, the Eastern Interconnection average frequency response of 2,308 MW/0.1 Hz provides a safe margin above the first step of underfrequency load shedding (59.7 Hz) for the single-event criteria loss of 4,500 MW.

For the ERCOT Interconnection, two variables (high pre-disturbance frequency and time) have a statistically significant correlation with frequency response. The indicator of high pre-disturbance frequency has the largest impact on frequency response, followed by time. High pre-disturbance frequency is negatively correlated with frequency response, while time is positively correlated with frequency response. Statistically significant positive correlation with time implies a frequency response improvement with time.

For the Québec Interconnection, three variables (load level, winter, and on-peak hours) have a statistically significant correlation with frequency response. Interconnection load has the biggest impact on frequency response, followed by the indicators of winter and on-peak hours. All these variables are positively correlated with frequency response.

For the Western Interconnection, only one variable (high pre-disturbance frequency) has a statistically significant negative correlation with frequency response.

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[66] The correlation between time variable and frequency response is negative and this is equivalent to the fact that the slope is negative and the trend line is decreasing function. However, the correlation is <u>not</u> statistically significant. This leads to the failure to reject the null hypothesis of zero correlation. So even though the decreasing trend for frequency response in time was observed, there is a high probability that the negative correlation and the negative slope occurred by chance.

[67] 2012 State of Reliability Report, May 2012, http://www.nerc.com/files/2012_SOR.pdf

[68] At significance level of 0.1.

In summary, a high pre-disturbance frequency and interconnection load level are the two factors that significantly affect frequency response—the high pre-disturbance frequency results in a longer time for the frequency to fall below the governor dead-band setting and degrades frequency response.

ALR3-5 (M-8) Interconnection Reliability Operating Limit Exceedances

Background

The *State of Reliability 2013* report reviewed the Interconnection Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances metric. In the past, this metric has been used to determine the number of times an IROL was exceeded in the Eastern Interconnection and the number of times an SOL was exceeded in the Western and ERCOT Interconnections. Since the metric was first introduced, all regions now recognize IROLs and are anticipated to be able to report on IROL exceedances in 2014. Therefore, metric ALR 3-5 (M8) was modified to remove the SOL reporting language in late 2013.

This metric measures the number of times that a defined IROL was exceeded and the duration of these exceedances. Exceeding an IROL could lead to widespread outages if prompt operator control actions are not taken to return the system to within normal operating limits. In addition, exceeding the limits may not directly lead to an outage but may put the system at unacceptable risk if the operating limits are exceeded beyond T_v.[69] To monitor how quickly an IROL is returned to within normal limits, the data is grouped into four time segments, as shown in Table 4.5.

Table 4.5: Exceedance Duration Segment

Time Range	IROL/SOL Duration
Time Range 1	10 secs < Duration ≤ 10 mins
Time Range 2	10 mins < Duration ≤ 20 mins
Time Range 3	20 mins < Duration ≤ 30 mins
Time Range 4	Duration > 30 mins

[69] T_v is the maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

Eastern Interconnection

Figure 4.6 shows the number of IROL exceedances by quarter and time range of exceedance for the Eastern Interconnection for 2011–2013. The second quarter shows the most exceedances for the Eastern Interconnection in all years due to planned transmission outages resulting in congestion and higher flows on the remaining paths.

It is notable that most of the exceedances occur in Time Range 1 and 2, and that for the three years included in the analysis, the number of exceedances decreased in both of those time ranges. However, in 2013, there were also exceedances that had durations that put them into Time Range 3 and Time Range 4, meaning that the duration of these three exceedances were greater than 20 minutes; two of them were greater than 30 minutes.

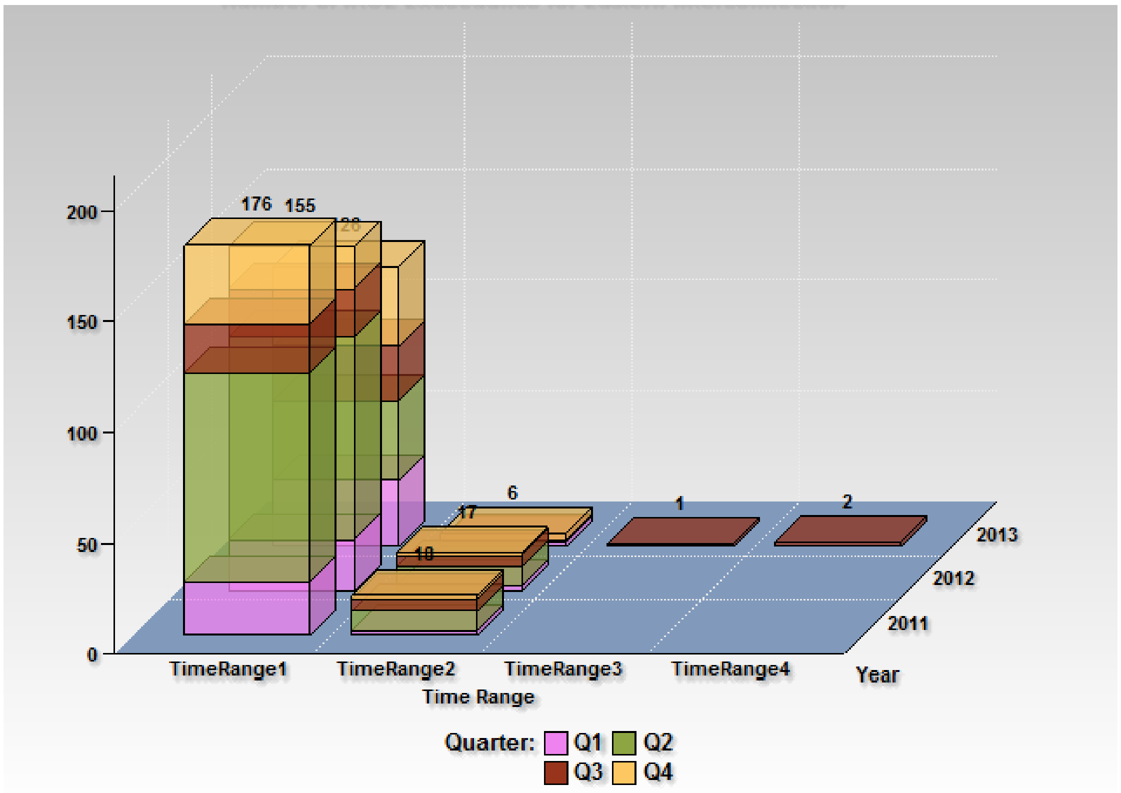

Figure 4.6: Eastern Interconnection IROL Exceedances

Western Interconnection

WECC is making changes in 2014 to the way its limits are calculated to allow the calculation of IROL limits and will therefore be able to report on IROL exceedances going forward. Figure 4.7 shows the number of SOL exceedances separated by quarter and segment type for the Western Interconnection from 2011 through 2013.

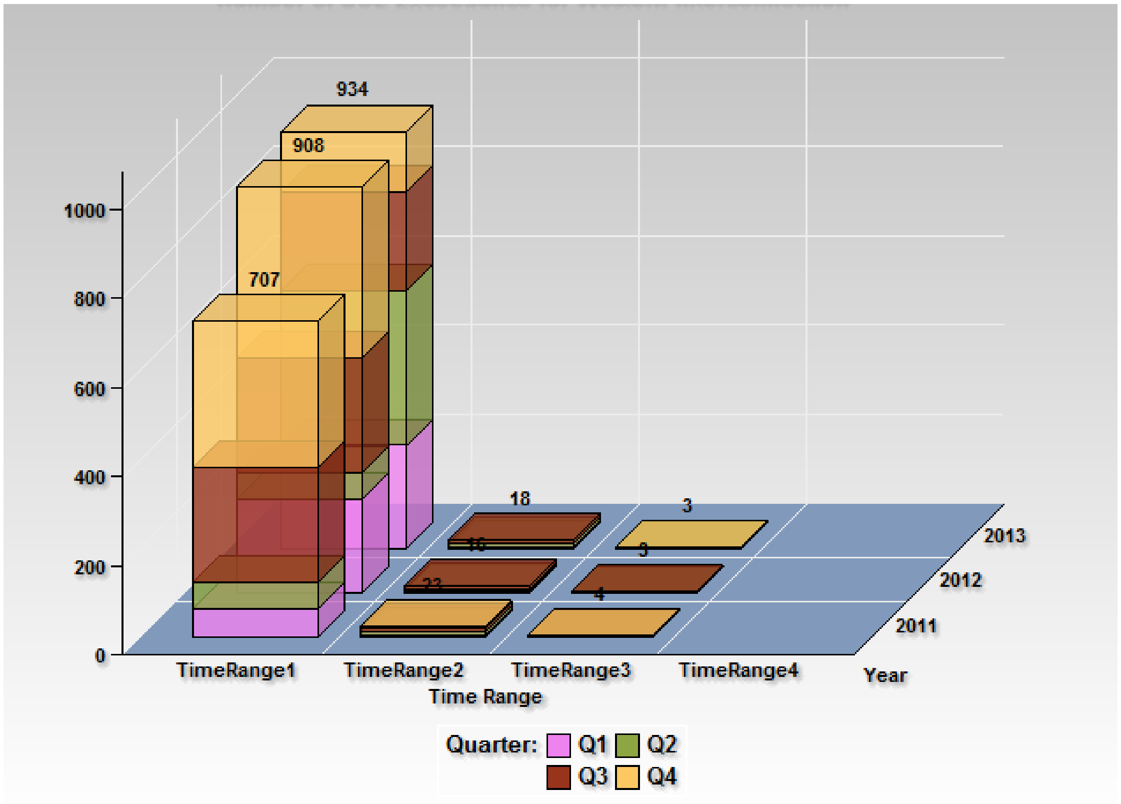

Figure 4.7: Western Interconnection ALR3-5 SOL Exceedances

ERCOT Interconnection

Figure 4.8 shows that the number of IROL exceedances was greatly reduced from 2011 through 2013. Some contributions to the improved performance are smoother transitions in limit values due to the implementation of real-time analysis tools, and more available transmission. The completion of a major transmission expansion project resulted in a major drop in exceedances between the fourth quarter of 2012 and the first quarter of 2013. The result is that the IROL that contributed to most of the exceedances has been mitigated, so exceedances are not expected to occur going forward.

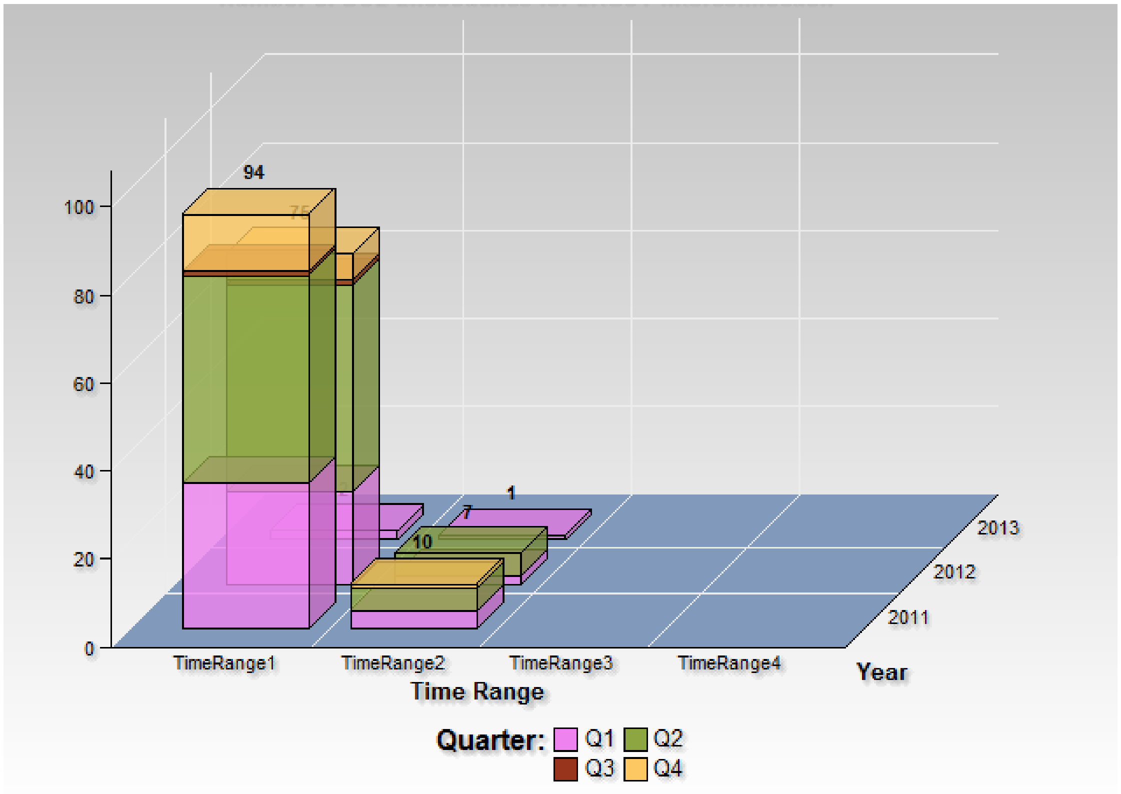

Figure 4.8: ERCOT Interconnection ALR3-5 SOL Exceedances

Québec Interconnection

To maintain the anonymity of the reporting entity, information regarding the assessment of Québec Interconnection is not disclosed, despite the data's being available.

ALR4-1 (M-9) Protection System Misoperations

Background

Protection system misoperations were identified as an area that requires further analysis in the *State of Reliability 2013* report. The improvements to the data collection process that the Protection System Misoperations Task Force (PSMTF) and System Protection Control Subcommittee (SPCS) proposed in 2013 have been implemented and should improve the accuracy of future misoperation reporting. Based on the recommendation by the PSMTF and SPCS, the respective protection system subcommittees within each Regional Entity began analyzing misoperations on an annual basis in early 2014. The *State of Reliability 2013* report also recommended that additional analysis be performed to determine how often misoperations are involved with reportable system disturbances and whether the misoperation was causal to the event or exacerbated the seriousness of the disturbance.

Assessment

Figure 4.9 shows the misoperation rate by Region. The misoperation rate reflects the ratio of misoperations to total operations for the entire BES, 100 kV and above. This ratio provides a stable way to trend the rate of misoperations as compared to a misoperation count alone, where weather and other factors can influence the count. Total protection system operations was first requested with the fourth quarter 2012 misoperation data. Having the total number of operations for the reporting periods in 2013 allows for a consistent way to normalize and trend protection system misoperations over time.

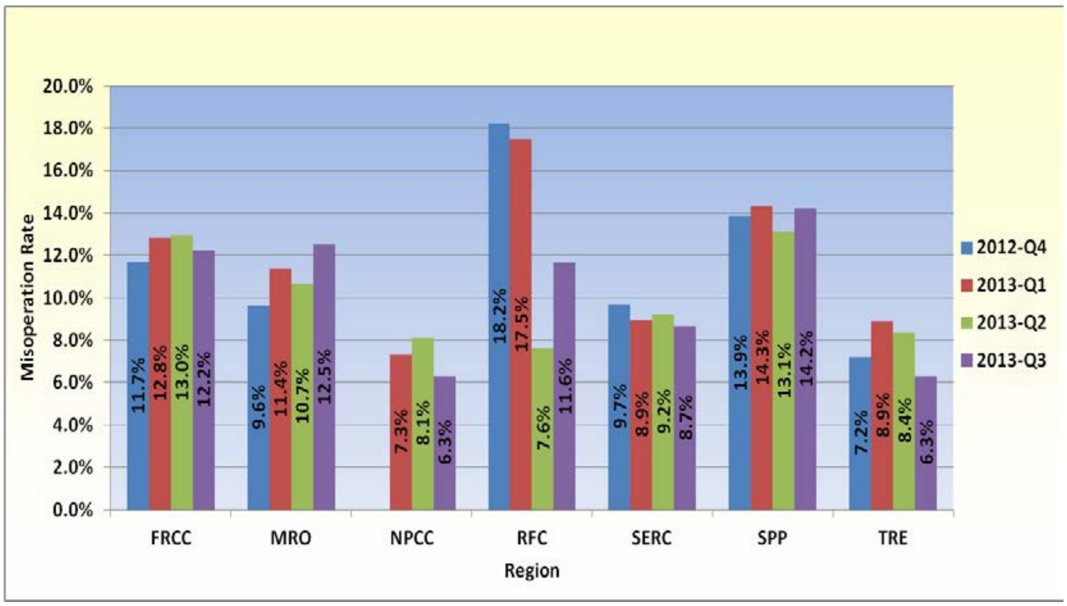

Figure 4.9: ALR4-1 Misoperation Rate by Region

Figure 4.10 shows misoperations on a monthly basis from April 1, 2011, to September 30, 2013. Overall, the trend is periodic, with peaks in the spring and summer months of all three years.

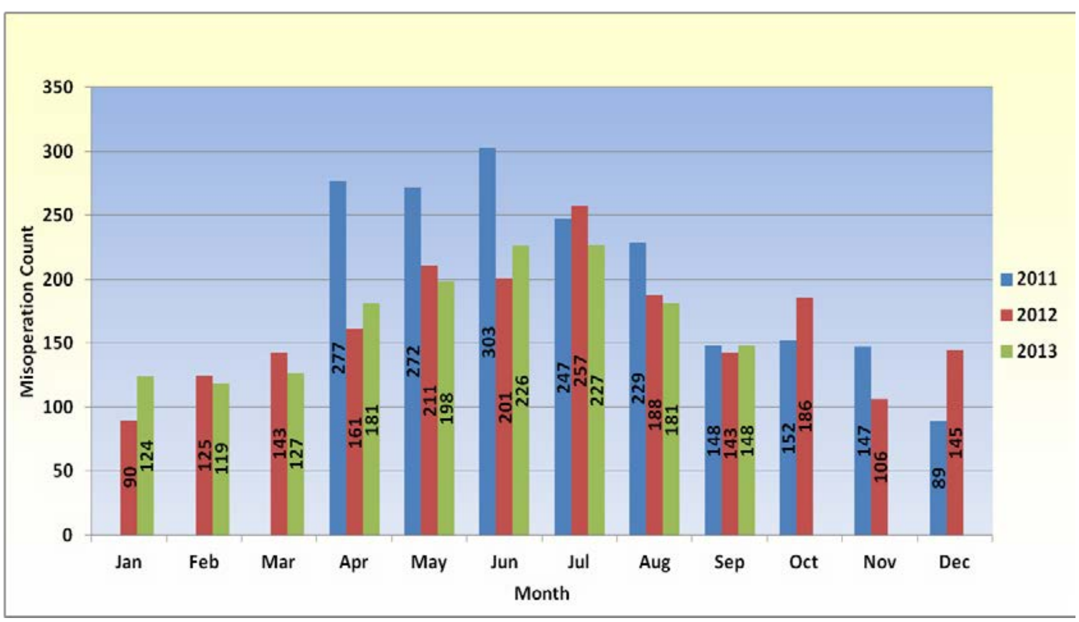

Figure 4.10: NERC Misoperations by Month (2Q2011–4Q2013)

Figure 4.11 illustrates the top-three cause codes being assigned to misoperations by the TOs: incorrect setting, logic, or design error; relay failures/malfunctions; and communication failure. These three cause codes have consistently accounted for 65 percent of all misoperations since data collection started in 2011.

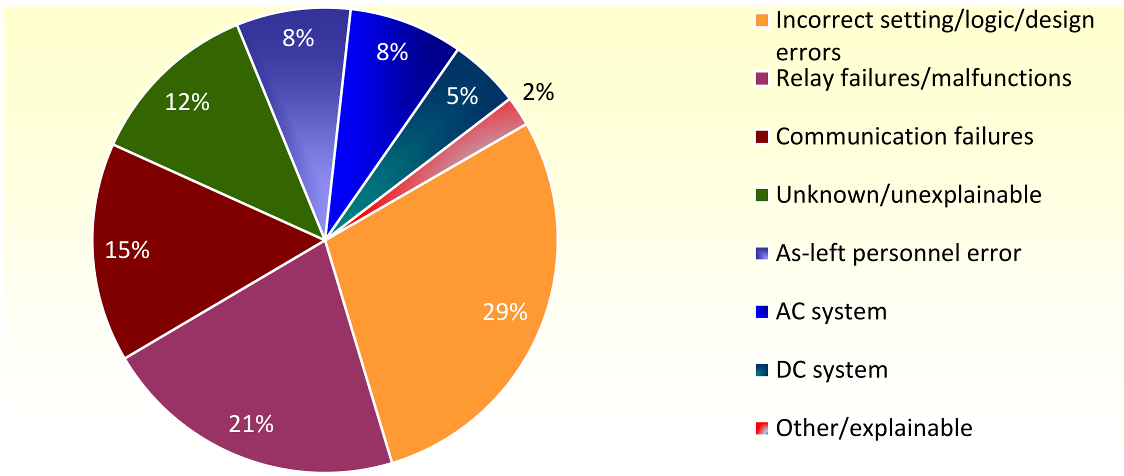

Figure 4.11: NERC Misoperations by Cause Code from 2011Q2 to 2013Q3[70]

In 2013, 71 transmission-related system disturbances resulted in a NERC Event Analysis reported event. Of those 71 events, 47 events (about 66 percent), had associated misoperations. Of these 47 events, 38 events (about 81 percent), experienced misoperations that were contributory to and/or exacerbated the severity of the event. In several cases, multiple misoperations occurred during a single disturbance. Cause coding has not yet been completed for all 2013 events, but it is estimated that there were 60–75 misoperations associated with these 38 reportable events. Therefore, out of approximately 2,000 total misoperations in 2013, approximately 3.0 to 3.5 percent were causal to or exacerbated the severity of reportable system disturbances.

NERC is in the process of revising a number of Reliability Standards involving protection system misoperations.[71] To increase awareness and transparency, NERC will continue to conduct industry webinars[72] on protection systems and document success stories on how GOs and TOs are achieving high levels of protection system performance. The quarterly protection system misoperation trending by NERC and the Regional Entities can be viewed on NERC's website.[73]

As identified in the 2013 PSMTF final report, there are several areas where misoperation reduction is possible for entities. First, relay applications requiring coordination of functionally different relay elements should be avoided. Secondly, misoperations due to setting errors can potentially be reduced. Techniques that could be used to reduce the application of incorrect settings include peer reviews, increased training, more extensive fault studies, standard templates for setting standard schemes using complex relays, and periodic reviews of existing settings when there is a change in system topography. Finally, firmware updates may affect relay protection settings, logic, communications, and general information stored and reported by the relay. Entities should be aware of what version of firmware they have on their microprocessor-based relays. Entities should also monitor if the relay vendor has issued updated relay firmware.

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[70] Cause-coded Misoperation data for 2013 4Q is not available at this point.
[71] http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx
[72] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf
[73] http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx

Special Considerations

In the annual review of metrics, the PAS made a minor modification to ALR4-1 (M-9) to remove the interim method for calculation of the total number of operations. Previously, automatic operations were only available through TADS data, which only includes operations at 200 kV and above. This change was approved in December 2013.

NERC undertook an effort to collect data on total protection system operations to create a more useful metric for monitoring protection system misoperation performance. This data collection began with the reporting of fourth quarter 2012 misoperation data. Having the total number of operations for the reporting periods in 2013 facilitates a way to normalize and trend protection system misoperations over time.

ALR6-2 (M-11) Energy Emergency Alerts

Background

This metric was enhanced in 2013 by expanding the data collection to include counts and duration of all EEA events of all levels and unserved energy data for all EEA Level 3 occurrences that result in load shedding. This metric will account for the number and duration of Energy Emergency Alerts that are issued. All EEA Level 1, Level 2, and Level 3 occurrences can then be tracked to see whether there are any changes in frequency, duration, and load shed magnitudes of EEA occurrences over time.

As historical data is gathered on EEAs, trends provide a relative indication of performance measured at a BA or interconnection level. By definition, when an EEA Level 3 Alert is issued, firm-load interruptions are imminent or in progress. An EEA Level 3 indicates an issue with the real-time adequacy of the electric supply system. It may be due to a lack of fuel or dependence on transmission for imports into a constrained area, not simply a lack of available generation resources. The contributing factors for EEA Level 3 events need to be considered.

Reporting the duration and unserved energy of load shed events aids in determining the likelihood and duration of a load shed event following the issuance of an EEA Level 3. EEA Level 3 events are currently reported, collected, and maintained in NERC's Reliability Coordinator Information System (RCIS), as defined in NERC Standard EOP-002.[74]

Assessment

Table 4.6 shows the number of EEA Level 3 events from 2006 to 2013 at the Regional Entity level. Interactive quarterly trending is available at the Reliability Indicator's page.[75] In 2013 there were seven EEA Level 3 Alerts issued, with only one resulting in a loss-of-load event. Seven EEA Level 3 events were declared in 2013, which is significantly lower than the number that occurred in prior years.

Table 4.6: Energy Emergency Alert 3

Number of Events	Year							
	2006	2007	2008	2009	2010	2011	2012	2013
NERC	7	23	12	41	11	23	16	7
FRCC	0	0	0	0	0	0	0	1
MRO	0	0	0	0	0	0	0	0
NPCC	0	0	1	1	0	0	0	0
RF	0	3	1	0	2	0	1	0
SERC	4	14	2	3	4	2	7	0
SPP	1	5	3	35	4	15	6	2
TRE	0	0	0	0	0	1	1	0
WECC	2	1	5	2	1	5	1	4

[74] The latest version of EOP-002 is available at: http://www.nerc.com/files/EOP-002-3_1.pdf

[75] The EEA3 interactive presentation is available on the NERC website at: http://www.nerc.com/pa/RAPA/ri/Pages/EEA2andEEA3.aspx

The one EEA Level 3 event that resulted in load shed involved the interruption of 200 MW of load for two hours, or unserved energy of 400 MWh. This event was due to a number of factors that culminated with the failure of transmission system equipment that reduced the ability to serve all the load in the affected area.

The other six reported EEA Level 3 Alerts did not result in any loss-of-load events. These EEA Level 3 events fell into two categories. One category pertained to significant unplanned outages of resource supply due to generator trip or equipment failure, either the unplanned loss of one or more generation resources, or the unplanned loss of a major transmission facility that supplied generation into an area. These included quickly evolving events in which the entity had to use its reserves to serve its load and had to prepare for load shed to meet the next possible contingency. The other category consists of events in which transmission limitations in the form of Transmission Loading Relief (TLR)[76] events were in place and were affecting entities that rely upon import transactions to serve their load. These events did not involve sudden loss of generation or equipment failures; rather, they occur as loading increases over a period of time and the affected TOP responds by requesting various levels of TLR relief. The entities in this category used the EEA Level 3 to protect their firm transactions to avoid having to reduce load, and they called upon reserve sharing provisions to restore reserves.

In 2013, NERC began assessing the EEA Level 1 and Level 2 events as a part of this metric. Table 4.7 shows the number of EEA events at each of the levels and displays all the EEA alerts reported in 2013 by region (except for TRE). It is intuitive that more events occurred at Level 1 and Level 2, as those represent situations in which capacity emergencies are developing.

Table 4.7: EEA Level by Region

Region	EEA1	EEA2	EEA3	Total
FRCC	2	3	1	6
MRO	11	0	0	11
NPCC	5	11	0	16
RF	5	11	0	16
SERC	2	3	0	5
SPP	2	0	2	4
WECC	20	9	4	33
Grand Total	**47**	**37**	**7**	**91**

Figure 4.12 displays the cumulative amount of time at each EEA alert level. Since this data for all the alerts was only collected for 2013, there is not sufficient history to trend the data, which will continue to be gathered and analyzed going forward.

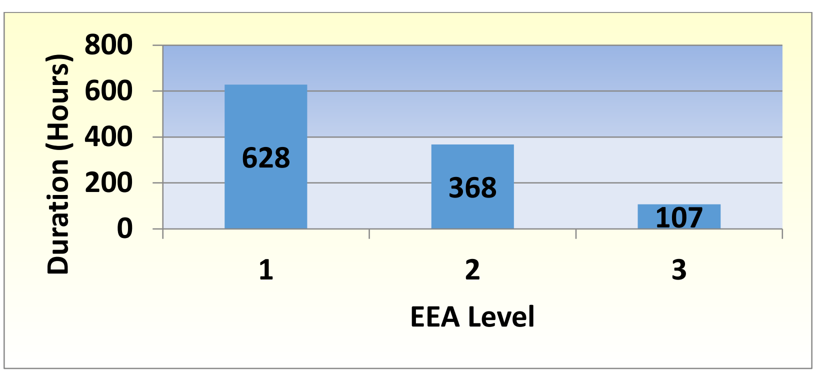

Figure 4.12: Duration (Hours) by EEA Level

[76] http://www.nerc.com/pa/rrm/TLR/Pages/default.aspx

Chapter 5 – Event Analysis

Background

The industry's voluntary event analysis program is providing valuable information for the ERO and industry to use to address potential threats or vulnerabilities to the reliability of the BPS. Since its initial implementation in October of 2010, the process has resulted in the collection of 399 qualified events being reported to the ERO and yielded more than 77 lessons learned, including 14 published in 2013.[77] NERC and the Regions assess every event to identify and share with industry the possible threats to reliability. This year the NERC Cause Code Assignment Process (CCAP) provided greater ability for historical trending and predictive analysis. Industry has actively participated in the assignment of cause codes as events, providing greater transparency on how NERC trends events; it also provides a great venue for active collaboration and sharing. This active collaboration is a testament to how much effort and resources are being expended in this area by the industry, as well as how important it is for the ERO and industry to truly understand the different contributors to events. The OC's Event Analysis Subcommittee (EAS) has been essential in the maturation of this process and has facilitated the active disseminations of many of the products that have been delivered to date. This chapter highlights some of the significant products that have been produced from this active collaboration.

Bulk Power System Awareness

The process for understanding the potential threats or vulnerabilities to the reliability of the BPS starts with understanding events and occurrences in the context in which they occur. NERC's Bulk Power System Awareness (BPSA) group and the eight Regional Entities monitor BPS conditions, significant events, and emerging threats for the 15 Reliability Coordinator regions in North America to understand the conditions and situations that could impact the BPS's reliable operation. This group also supports the development and publication of alerts and awareness products and facilitates information sharing among industry, the Regions, and the government during crisis situations and major system disturbances.

The first step in NERC's Event Analysis Program is to monitor and be aware of BPS events above a certain threshold of impact or risk. The group partners with Regional Entity staffs to monitor conditions on the BPS and allow the ERO to conduct in-depth, critical self-analysis of these events to identify trends and provide experience-based insight to prevent repeat occurrences. NERC's BPSA, in close coordination with the Regional Entities, shares the needed information with NERC and Regional Entity Event Analysis staff.

Overview and Accomplishments of the ERO BPSA Group

By The Numbers – Bulk Power System Awareness

- 480 new Event Analysis database entries initiated
- 250 daily reports published
- 46 special reports published during major system disturbances
- Received and processed:
  - 316 OE-417 reports
  - 42 EOP-004 system disturbance reports
  - 7 EOP-002 reports
  - 1,990 Intelligent Alarms notifications
  - 2,582 FNet notifications
  - 4,562 WECCnet messages
  - 1,709 Reliability Coordinator Information System messages
  - 156 Space Weather Predictive Center notifications
  - 149 Department of Homeland Security notifications
- 1 advisory (Level 1) alert issued
- 4 advisory (Level 1) alerts published, assisting ES-ISAC

[77] The link to the NERC Lessons Learned page: http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

As recognizable from the data above, many occurrences, notifications, and alarms occur frequently, with little or no real impact on the system at large. Being aware of the daily occurrences aids in the understanding of the size and complexity of the system. Registered entities continue to inform and collaborate with the ERO well beyond what is required in an effort to make sure all stay abreast of the state of the grid. Only a small subset of the occurrences of which the BPSA group is made aware rise to the level of a reportable event. When a registered entity experiences an event, the registered entity will recommend an initial category for the event, as outlined in the figure below. The categories listed in the Categorization of Events section do not cover all possible events.

Category 1

a. An unexpected outage, contrary to design, of three or more BPS facilities caused by a common disturbance. For example:
   i. The sustained outage of a combination of three or more facilities.
   ii. The outage of an entire generation station of three or more generators (aggregate generation of 500 MW to 1,999 MW); each combined cycle unit is counted as one generator.

b. Intended and controlled system separation by the proper operation of a Special Protection System Scheme (SPS) or Remedial Action Scheme (RAS) in Alberta from the Western Interconnection, or in New Brunswick or Florida from the Eastern Interconnection.

c. Failure or misoperation of BPS SPS/RAS.

d. System-wide voltage reduction of 3% or more that lasts more than 15 continuous minutes due to a BPS emergency.

e. Unintended BPS system separation that results in an island of 100 MW to 999 MW. Excludes BPS radial connection, and non-BPS (distribution) level islanding.

f. Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.

g. In ERCOT, unintended loss of generation of 1,000 MW - 1,399 MW.

h. Loss of monitoring or control, at a control center, such that it significantly affects the entity's ability to make operating decisions for 30 continuous minutes or more.
   Examples include, but are not limited to the following:
   i. Loss of operator ability to remotely monitor, control Bulk Electric System (BES) elements, or both.
   ii. Loss of communications from SCADA RTUs
   iii. Unavailability of ICCP links reducing BES visibility
   iv. Loss of the ability to remotely monitor and control generating units via AGC
   v. Unacceptable State Estimator or Contingency Analysis solutions

Category 2

a. Complete loss of all BPS control center voice communication systems for 30 minutes or more.

b. Complete loss of SCADA, control or monitoring functionality for 30 minutes or more.

c. Voltage excursions equal to or greater than 10% lasting more than 15 continuous minutes due to a BPS emergency.

d. Complete loss of off-site power (LOOP) to a nuclear generating station per the Nuclear Plant Interface Requirement.

e. Unintended system separation that results in an island of 1,000 MW to 4,999 MW.

f. Unintended loss of 300 MW or more of firm load for more than 15 minutes.

g. Interconnection Reliability Operating Limit (IROL) Violation for time greater than Tv.

Category 3

a. Unintended loss of load or generation of 2,000 MW or more in the Eastern Interconnection or Western Interconnection or Québec Interconnection, or 1,400 MW or more in the ERCOT Interconnection.

b. Unintended system separation that results in an island of 5,000 MW to 10,000 MW.

c. Unintended system separation (without load loss) that results in an island of Florida from the Eastern Interconnection.

Category 4

a. Unintended loss of load or generation from 5,001 MW to 9,999 MW

b. Unintended system separation that results in an island of more than 10,000 MW (with the exception of Florida as described in Category 3c).

Category 5

a. Unintended loss of load of 10,000 MW or more.

b. Unintended loss of generation of 10,000 MW or more.

Figure 5.1. Categorization of Events[78]

[78] Qualifying events are assigned to one of five categories based on the impact to the reliability of the BPS. The event categories are intended to allow the registered entity and Regional Entity to objectively identify event thresholds. For a more thorough review of the process see: http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf

In 2013, the NERC CCAP provided valuable information to the industry, including greater ability for historical trending and predictive analysis. The active participation by industry has greatly enhanced the accuracy in the assignment of cause codes as events are analyzed and trended, providing greater transparency on how NERC and the Regional Entities trend events. The process provides an ideal venue for active collaboration and sharing. See Table 5.1 for a consolidated chart of the reportable events since the program's inception and for 2013.

Table 5.1: Event Analysis Event Summary. The events by category since the initial implementation in 2010 and the event count for 2013

Event Category	Count (Total)	Count (2013)	Comments
CAT 1	267	102	
CAT 2	114	33	30 - EMS events (2b) (2013) 2 - LOOP events (2d) (2013) 1 – Loss of >300MW firm load for >15 minutes(2f)
CAT 3	14	6	
CAT 4	3	0	SW Winter Weather (2011) SW Blackout (2011) Derecho (2012)
CAT 5	1	0	Hurricane Sandy (2012)
Total CAT 1-5 Events	**399**	**141**	
Non-Qualified Occurrences reported	**1715**	**342**	

The plotting of the number events over time allows one to see if there is any sort of trending that is moving outside of the normal event count averages and is one indicator of the consistent reliability of the grid through a variety of external and environmental conditions (Figure 5.2).

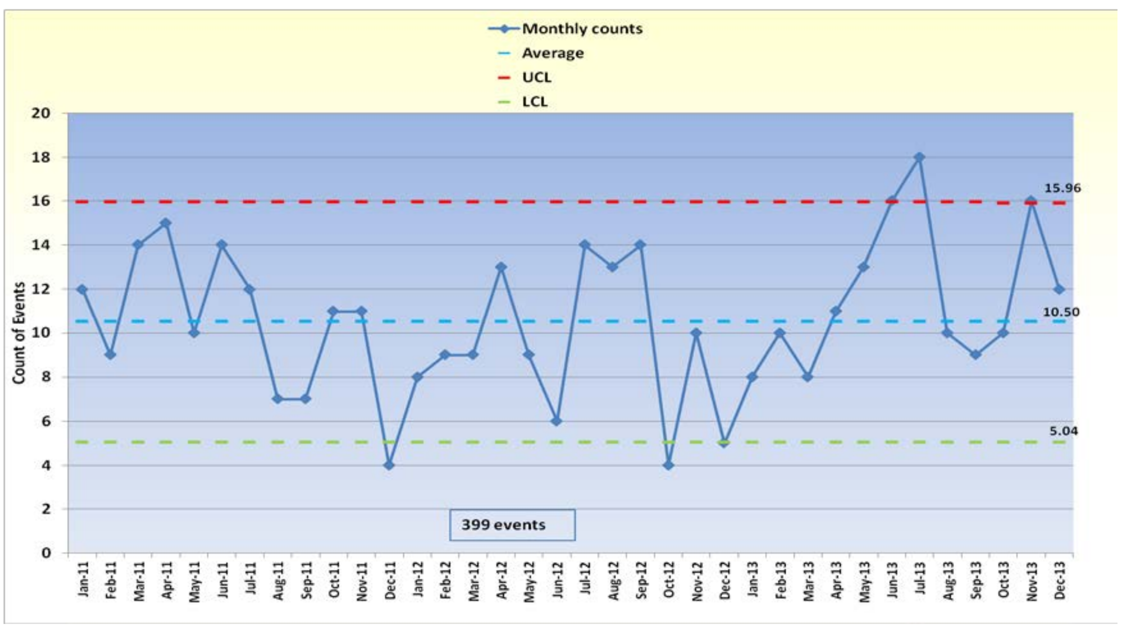

Figure 5.2: Trending of the Number Events over Time[79]

[79] Count of events by month with three-month average for control limit calculation. Surpassing the upper control limit in July of 2013 was largely due to environmental conditions, in this case, flooding and forest fires.

The above trending graph is of the 399 qualified events through 2013. The quality of the event reports is vital for the success of the NERC Event Analysis Program. The quality, detailed analysis, and investigations that entities performed have led to quality reports.[80] Good quality event analysis reports allow for more accurate cause coding of events and has led to better trending. Better trending leads to timely identification of issues being communicated back to the industry.

Through the Event Analysis Program, NERC assesses every event report to identify and then share with industry the apparent threats to reliability that may be emerging. The NERC CCAP manual[81] was updated in February 2013. Cause coding has allowed for easier trending for all event causes. While the root cause of every event can not necessarily be determined, many of the contributing causes or failed defenses can be determined, analyzed, and trended to provide valuable information to the industry. Figure 5.3 shows the overall trends for the contributing causes of events.

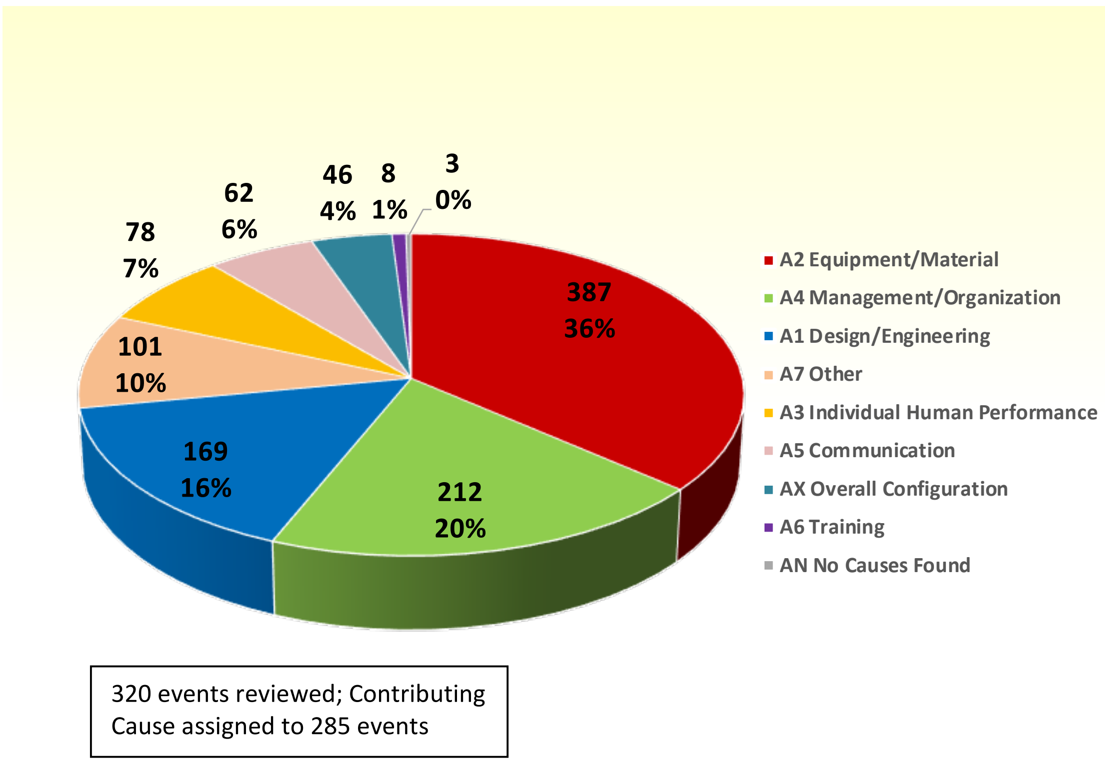

Figure 5.3: The Percentage of Contributing Causes by Major Category

Identification of these large areas of concern allow NERC and industry to prioritize and search for actionable threats to reliability. For example, from the chart above, one can see the large amount of equipment that is damaged or fails that is linked to the causes of events. With the systematic approach to trending all of the event data, the different types of failed or damaged equipment can be parsed from the aggregate data. In this case, circuit breaker failures were found to be the single-largest contributor to events (see Figure 5.4). This is often the failure mode of an event—what one sees as the apparent cause. Note that when possible, the distinction is made between equipment that fails due to damage (both human caused and nature caused), end of life, or other related attributes that result in the equipment or material not functioning as desired. For the purpose of the following

[80] http://www.nerc.com/pa/rrm/ea/EA Program Document Library/NERC-Report-Quality.pdf
[81] http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/NERC_Cause_Code_Assignment_Process_March_2014_rev20140324%20SLS.pdf

analysis, failed equipment relates to all of the aforementioned attributes, unless a specific failure mechanism is mentioned.

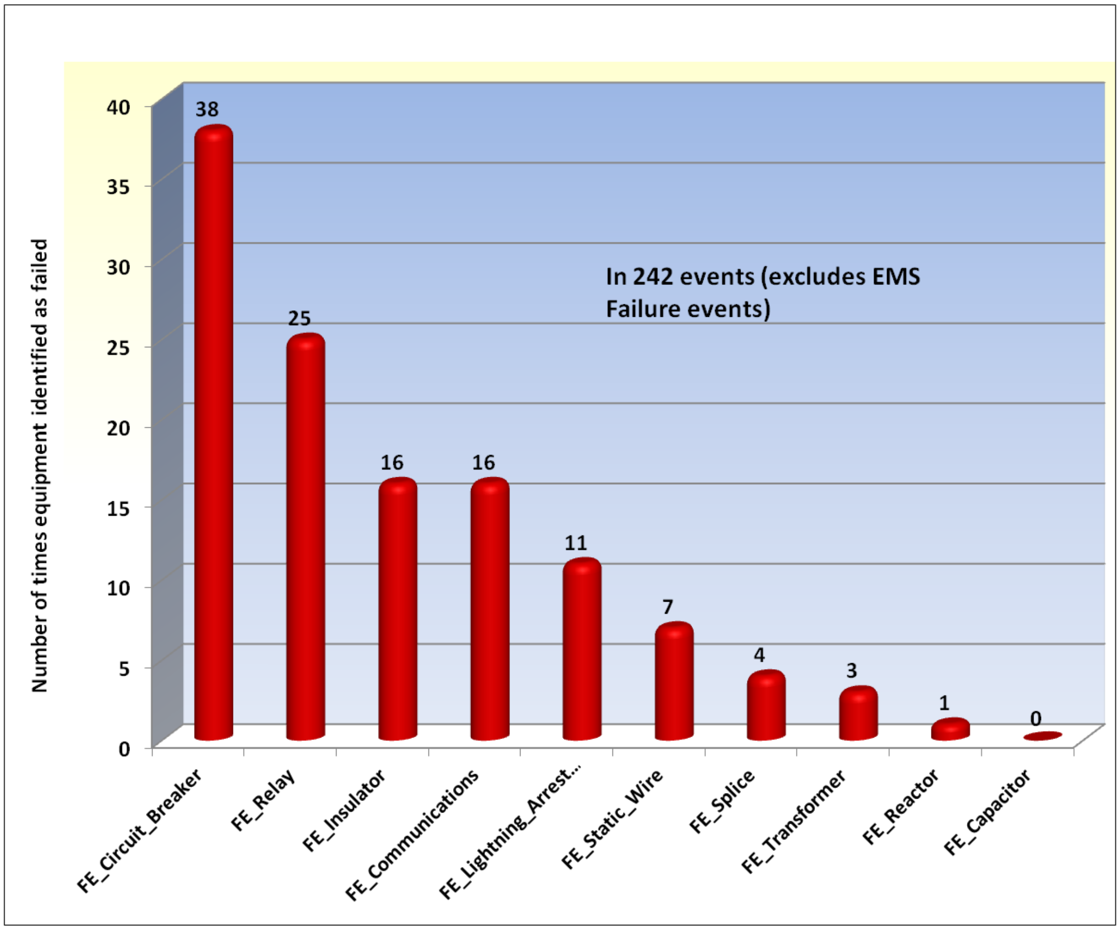

Figure 5.4: Failed Equipment Identified during Review of Event Reports

Further analysis of circuit breakers suggested a trend for a specific type of circuit breaker in many of the observed and reported events. NERC was then able to develop a case history. An example of the benefits of industry and NERC analyzing events is a recently identified trend related to the failure mode of a specific type of 345 kV breaker.

Figure 5.5 shows a timeline during which a trend was identified for a specific type of 345 kV SF_6 puffer-type circuit breaker failure.

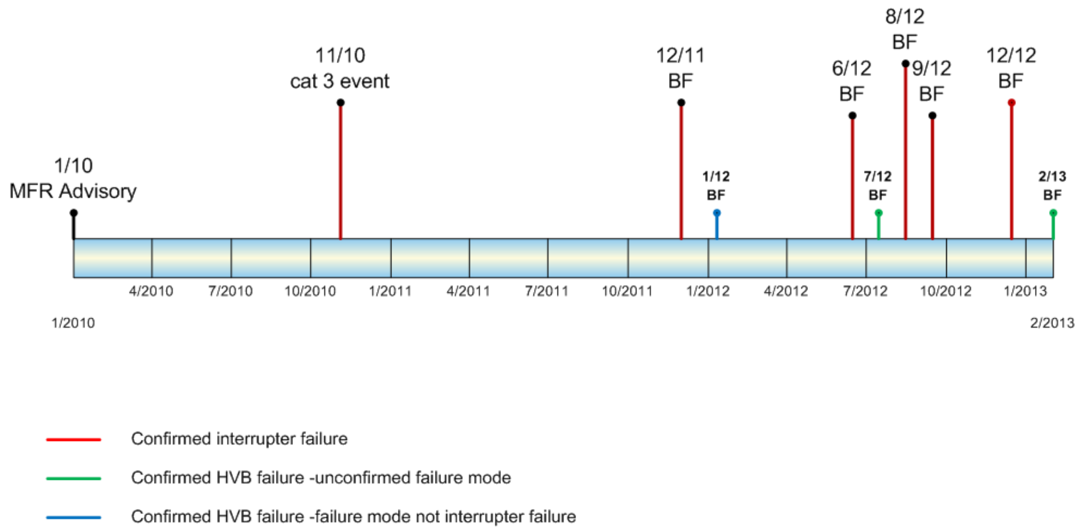

Figure 5.5. Timeline for Identification of a Trend in 345-kV SF_6 Puffer-Type Circuit Breaker Failures

These analyses resulted in NERC's issuing a Level 1 Advisory Alert regarding identification of a trend in 345 kV SF_6 puffer-type circuit breaker failures and the potential risk it posed to the reliability of the BPS. The purpose of the alert was to ensure that industry was aware of the recent failures and previously published maintenance advisories, so appropriate action could be taken by entities that utilize this particular equipment.

While the alert was advisory in nature and did not require specific action to be taken, this was a reliability risk suited for close collaboration with the North American Generator Forum and North American Transmission Forum, as well as certain trade associations with members that may have this particular 345 kV equipment. This advisory provided an excellent opportunity for NERC to work directly with the forums and trades to determine the extent of the condition and address the potential risk to the BPS.

NERC continues to conduct cause analysis training with staff from the Regions and registered entities. As of December 2013, personnel from all eight Regions and 668 persons from 145 different registered entities have received cause analysis training—more than 5,400 hours of training.

A similar identification of trends can be observed in the large contribution of “less than adequate” or “needs improvement” areas of management and organizational practices that contribute to events. Many of these threats can be identified and shared with the industry for awareness. For example, in Figure 5.6, the identification of some of the particular challenges to organization and management effectiveness are identified.

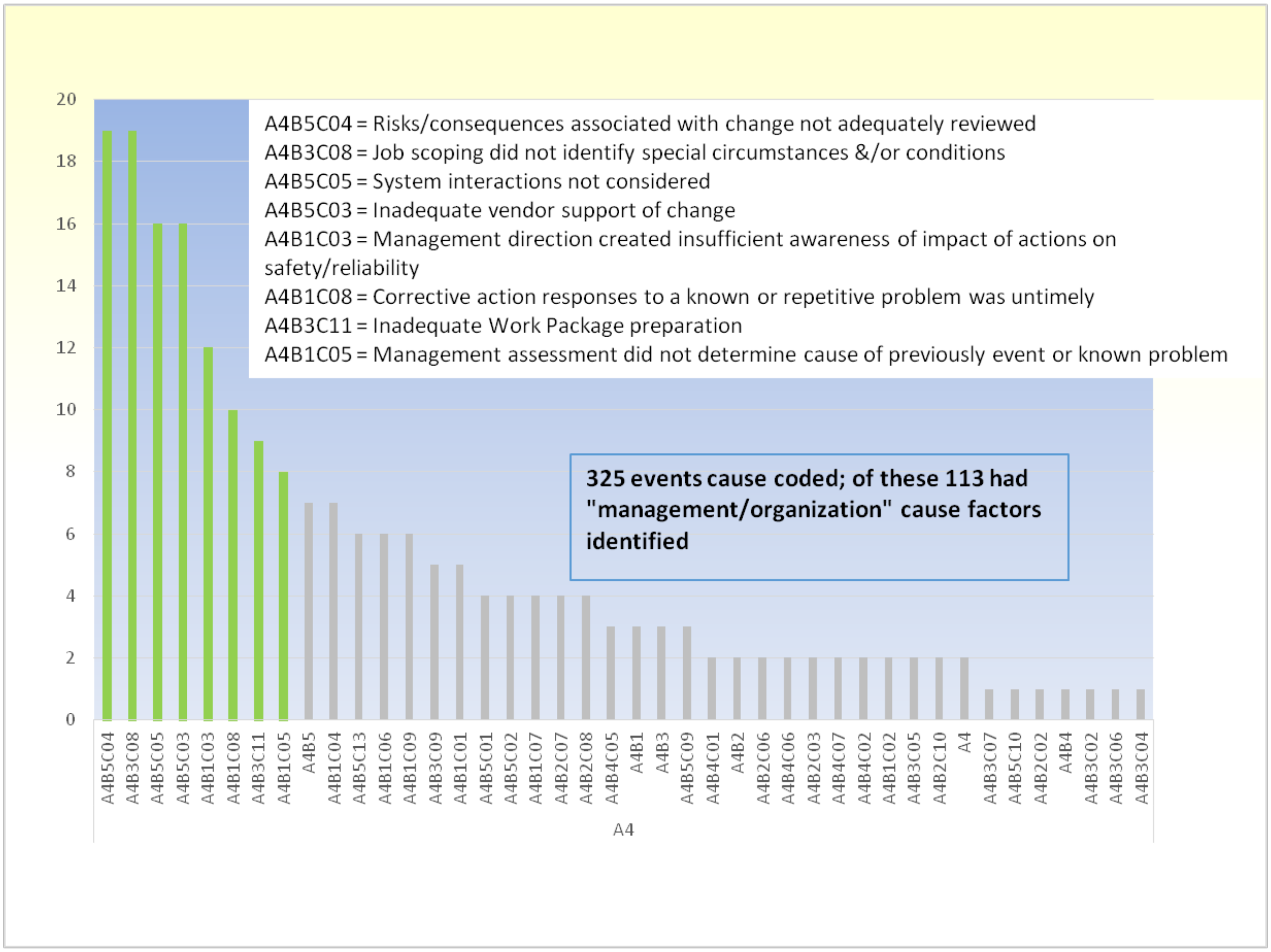

Figure 5.6: “Less than adequate” or “Needs improvement” Management/Organization Challenges that Contributed to an Event

Management of complex systems and organizations is a challenge in every industry, and the percentage of events with these contributing factors is collectively found in other industries.

Many of the most frequently identified contributing causes for events seen in Figure 5.6 were found present in the severe cold weather events. NERC, in close collaboration with the regional staff and the industry, published a report titled, *Assessment of Previous Severe Winter Weather Reports 1983-2011* to provide a review and comparison of previous winter weather events.[82] This review and a cold weather training package were provided to the industry to assist in their winter weather preparation.

Additionally, NERC conducted an industry-wide webinar in October 2013. Over 350 owners, users, and operators attended a webinar that provided the industry reports and training material in preparation for the upcoming winter weather forecasts and entity cold weather preparedness. During the webinar, the impacts from both the February 2011 Southwest Cold Weather Event and previous cold weather events were discussed. The webinar encouraged GOs and GOPs to focus on areas that were observed in past events, such as inspecting and maintaining

[82] These reports can be found at http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx .

heat trace equipment and thermal insulation, erecting adequate wind breaks and enclosures, and taking measures to protect instrument lines and equipment prior to the onset of winter weather.

NERC also reviewed the *Assessment of Previous Severe Winter Weather Reports 1983-2011* during the webinar. This report provides a review and comparison of the previous winter events cited in the FERC and NERC staff Report.[83] This was to remind industry that generators experienced weather-related outages and rolling blackouts in previous events, and lessons learned from these events could have prevented outages in more recent winter events.

The OC-developed Reliability Guideline[84] was also reviewed. This guideline provides a general framework for developing an effective winter weather readiness program for generating units throughout North America. Although the NERC *Winter Reliability Assessment 2013-14* was expected to be published later in November, attendees were given a preview of the draft. NERC also covered the NOAA Winter Outlook, resource adequacy, and seasonal reliability issues were also covered during the webinar.

Attendees were also introduced to a Cold Weather Event Training Package[85] designed by NERC training staff to assist non-traditional cold weather registered entities properly prepare for cold weather events. The materials were designed to be a guide to training sessions. These materials have been created as a foundation for training and remain in PowerPoint format to allow for customization based on registered entity needs. The NERC Event Analysis Program continues to establish the appropriate balance of data reporting for analysis and use by the industry. NERC is investigating ways to sustain positive efforts and improve the process.

Individual Human Performance

Analysis of event reports to date has identified possible workforce capability and human performance challenges that pose threats to reliability. Workforce capability and human performance is a broad topic and can most simply be divided into management, team, and individual levels. The following paragraphs provide more details on the types of errors that were observed in BPS events since the inception of the NERC Event Analysis Program, specifically events that involved human error or less-than-adequate training.

Generally, individual error is classified using the mode of performance in which the individual was operating when the error was committed. The NERC CCAP uses a popular methodology developed by Jens Rasmussen[86] in which errors occur in one of three modes of human performance, depending on the nature of the task and the level of experience with the particular situation. When information is first perceived and interpreted in the processing system, that information is processed cognitively in either the skill-based, knowledge-based, or rule-based levels.

Additionally, when contributing causes are considered, over half of the event reports to date indicate some management or organizational challenges. In an effort to support industry with these challenges, NERC held its second annual Human Performance conference in Atlanta, *Improving Human Performance on the Grid,* at the end of March 2013. The focus this year was not only on individual human performance, but the organizational and management challenges around human capital. The conference included industry and related professionals in the field, with over 200 attendees from all regions. The conference and associated workshops were very well received. NERC supported similar venues for industry in the spring in Edmonton, Canada, as well as in the fall in Salt Lake City. NERC provided industry support in this area to well over 250 registered entities across the eight Regions.

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83 http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/SW_Cold_Weather_Event_Final.pdf

84 http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Relibility_Guideline_Generating_Unit_Winter_Weather_Readiness.pdf

85 http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx

86 *Skills, rules, and knowledge: signals, signs and symbols and other distinctions in human performance models*. IEEE Transactions: Systems, Man & Cybernetics, 1983, SMC-13, pp.257-267.

The full conference presentations for the past Human Performance conference at NERC can be found at http://www.nerc.com/pa/rrm/hp/Pages/default.aspx.

Monitoring and Situation Awareness (Real-Time Tools)

Energy Management Systems (EMSes), including SCADA, digital or analog communications, and real-time tools, are vital for maintaining situational awareness and making operating decisions at both the individual and the organizational level. EMS systems are extremely reliable and are highly redundant. However, an outage of the EMS reduces visibility into a portion of the BES and increases the potential risk to the reliability of the BPS. The NERC Event Analysis Program has received over 80 Category 2b event reports in which a complete loss of SCADA, monitoring, or control has lasted for more than 30 minutes. NERC's commitment to active collaboration and sharing has allowed more information about these events to be adequately reviewed and shared among NERC Regions and the affected entities.

The Events Analysis Subcommittee (EAS) developed an Energy Management System Task Force (EMSTF) to analyze the events and data that were being collected about EMS outages and challenges. Industry also recognized that many EMS outages were significantly less than the 2b categorization yet impacted the decision-making activities for which the EMS is used. The 1h event category was created to learn more about these type of events. This category allows the EMSTF to collect a greater number of the occurrences of EMS partial outages and share this information with the industry.

From the event analysis reports and the work of the EAS, NERC published four lessons learned specifically about EMS outages and worked to build and support an industry-led EMS task force to support the EAS, under the NERC OC. The hard work and active sharing of this task force has reduced some of the residual risk associated with the potential loss of situation awareness and monitoring capability associated with this type of event and will continue to provide valuable information to the industry.

With the support of the EMSTF, NERC hosted its first Monitoring and Situational Awareness Conference Focused on Improving Energy Management Systems (EMS) reliability in Denver, September 18–19, 2013. The conference was scheduled to coincide with the NERC OC/PC/CIPC meetings. The conference brought together more than 90 operations and EMS experts from more than 55 registered entities, and a variety of vendors and consultants. The entities that attended came from all of the Regions.

The first day of the conference focused on the analysis of EMS outages and response strategies for alleviating the risk involved when EMS functionality is degraded or completely lost. The feedback from participants has been extremely positive. Attendees liked the technical nature of the presentations and the takeaways they could use to improve the processes and procedures at their own companies. Attendees greatly appreciated the openness with which the EMS shared their issues and corrective actions. Also appreciated was the platform that NERC provided to transparently share the events and learn from them. Industry requested a second workshop for 2014.

SCADA and real-time reliability tools are vital for maintaining situational awareness and making operating decisions at both the individual and the organizational level. EMS systems are typically extremely reliable and redundant; however, an outage of the EMS system increases the risk to the reliability of the BPS. Industry has demonstrated appropriate responses to EMS outages, and the ERO can now more accurately assess the residual risk to the BPS from EMS outages.

The full conference presentations for the past Monitoring and Situation Awareness conference can be found at http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx.

Summary

The Event Analysis Program continues to provide valuable information for the industry to use to address potential threats or vulnerabilities to the reliability of the BPS. This continued active collaboration remains a testament to how much effort and how many resources are being expended in this area by the industry, as well as how important it is for the ERO and industry to truly understand the different contributors to events. The continued cooperation and collaboration with the industry is the hallmark to this program's success.

The ability to identify specific pieces of equipment that are potential threats, as well as emerging trends that increase risk to the system, illustrates the value of the event analysis program. These outcomes, coupled with the ability to actively share the information through lessons learned, webinars, technical conferences, and related venues, remain critical to the sustainment of high reliability.

Chapter 6 – Spare Equipment Database Initiative (2014)

Background

In June 2010, NERC issued a report titled *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*.[87] In a postulated high-impact low-frequency (HILF) event, such as a coordinated physical or cyber attack or a severe geomagnetic disturbance (GMD), long-lead-time electric transmission system equipment may be damaged. This could adversely impact system reliability.

Following a HILF event, increased intercompany coordination will help maximize the use of available spares in restoring the grid, thereby increasing the resiliency of the system. This chapter discusses a framework to facilitate that coordination.

Purpose

The purpose of the Spare Equipment Database Working Group (SEDWG) is to recommend a uniform approach to collecting information on long-lead-time electric transmission system equipment and develop a process for utilities to request assistance from other utilities.[88] Data collection is contained in the Spare Equipment Database (SED). The intent of the database is not to replace or supersede other existing transformer-sharing agreements. Rather, the intent is to facilitate timely communication of available equipment following a HILF event.

Spare Equipment Database

SEDWG reviewed various types of long-lead-time equipment, where "long lead time" is defined as six months or more. Following the review, it was determined that the initial focus should be large power transformers and generator step-up (GSU) transformers. In addition to long lead times, large power transformers also require substantial capital to secure. For these reasons, owners typically maintain an appropriate limited number of spares in the event of a failure. It may be beneficial in the future to expand SED to include other types of long-lead-time equipment.

2013 and 2014 Activities

In 2013, the primary focus of SEDWG was to increase participation. To that end, SEDWG worked with NERC to host a webinar to explain the program to registered entities and to solicit new participants. In addition, presentations were made at a variety of industry forums, including the NERC PC, MRO and RF regional meetings, and the American Public Power Association. The SEDWG also initiated development of a metric. In 2014, SEDWG will continue to increase SED awareness and participation and will complete the development and proposal for the metric.

Confidentiality of SED Process

Confidentiality has been and continues to be an important aspect of the SED. Participating organizations voluntarily identify and report spare equipment that meets predefined criteria in the database. The data collected provides essential information to enable automated queries of available equipment. In addition, equipment owner information is required to facilitate communication following a HILF event.

To maintain confidentiality of the information, SED utilizes a double-blind approach to preserve the anonymity of the registered SED participants, the requestor and the owner of the equipment.

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[87] *High Impact, Low Frequency Event Risk to the North American Bulk Power System*, June 2010, http://www.nerc.com/pa/ci/resources/documents/hilf_report.pdf

[88] This task force will support the Electricity Sub-sector Coordinating Council's Critical Infrastructure Protection Roadmap, work plan items: 1) G - Critical Spares, and 2) P- GMD – Restore the Bulk Power System.

To initiate the search, the requestor completes an online form in SED and the program conducts a search. Upon completion, the requestor and NERC administrator are notified of the success of the search. From there, the SED program initiates a double-blind search-response procedure. SED generates messages to each unnamed TO identified by the search without disclosing what equipment is needed, how many pieces of equipment are requested, or the name of the requestor.

Owners who wish to proceed with discussing a sale/lease/exchange can use the double-blind search process to respond to the unnamed requestor to open an active discussion. Any decision to provide additional information is the responsibility of the owners. The NERC SED administrator is informed of all communications conducted via the SED link. The requestor and owner may then work toward a settlement acceptable to both parties.

A complete description of the SED search process and a special report on the SED can be found on NERC's website.[89]

Registration and Contact Information

For further information related to the SED program, please visit:
http://www.nerc.com/pa/RAPA/sed/Pages/Spare-Equipment-Database-(SED).aspx

[89] *Special Report: Spare Equipment Database System*, October 2011, http://www.nerc.com/docs/pc/sedtf/SEDTF_Special_Report_October_2011.pdf

Appendix A – Statistical Analysis for Chapter 3

Study Method

Defining BPS Impact from Transmission Risk

To define the impact, or severity, of each TADS event, the SRI quantitatively compares events. The TADS outage data is used to populate the statistical analysis study. For this analysis, the transmission outage impact component of the SRI quantifies BPS impacts. Since transmission outages are a significant contributor to the overall SRI, this chapter focuses on categorizing the individual TADS events based on TADS outage ICCs.

The SRI presented in Chapter 2 consists of several weighted risk impact components: generation, transmission, and load loss.[90] The transmission outage impact component of the SRI is defined as $w_T \times N_T$ where w_T is a weighting factor of 30 percent and N_T is the severity impact of a given day's transmission outages on the BPS based on TADS outages.

In this appendix and in Chapter 3, Equation A.1 is used to calculate the transmission severity component of a TADS event. The severity of a transmission outage is calculated based on its assumed contribution of power flow through transmission circuits. The average power flow MVA values, or equivalent MVA values used in Equation A.1, are shown in Table A.1. These equivalent MVA values are also applied to the denominator of the transmission severity equation to normalize the function. The TADS event severity is then analyzed by ICC to investigate relative information between the ICCs instead of being added to generation and load-loss components to calculate a daily SRI as used in Chapter 2.

For normalization, the total number of transmission circuits from the same year as the event is multiplied by each voltage class's equivalent MVA rating. For example, if an outage occurred in 2009, the normalization would use the total number of transmission circuits in 2009. This allows comparison of TADS events across years while taking into account the changing number of circuits within the BPS.

$$Transmission\ Severity_{Trans} = \frac{\sum_{Voltage\ Class}(MVA_{avg} \times AC\ Circuits\ Outages)}{\sum_{Voltage\ Class}(MVA_{avg} \times Total\ AC\ Circuits)}$$

Equation A.1

Table A.1: Transmission Severity Equivalent MVA Values

Voltage Class	Equivalent MVA Value
200–299 kV	700
300–399 kV	1300
400–599 kV	2000
600–799 kV	3000

[90] http://www.nerc.com/docs/pc/rmwg/pas/index_team/sri_equation_refinement_may6_2011.pdf, pp. 2-3.

Determining Initiating Causes and Probability

TADS events are categorized by ICCs.[91] These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity. The procedure illustrated in Figure A.1 is used to determine a TADS event's ICC. The procedure that defines ICCs for a TADS event allows ICC assignment to a majority of transmission outage events recorded in TADS. There are 18,754 events with ICCs assigned, comprising 99.4 percent of the total number of TADS events for the years 2008–2013. These events reflect 98.8 percent of the total calculated transmission severity of the database. Table A.2 provides the corresponding available event data by year.

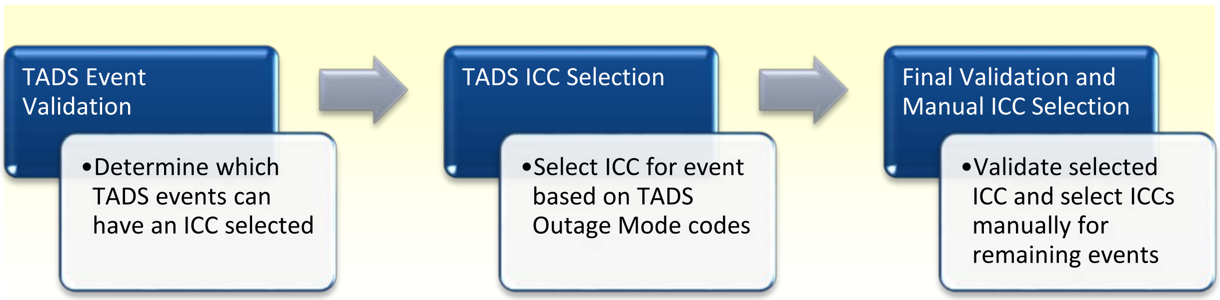

Figure A.1 TADS Event Initiating Cause Code Selection Procedure

Table A.2: TADS Outage Events Summary (2009–2013)						
Summary	**2009**	**2010**	**2011**	**2012**	**2013**	**2009-2013**
Number of TADS events	3,705	3,917	3,934	3,753	3,557	18,866
Number of events with ICC assigned	3,684	3,895	3,894	3,724	3,557	18,754
Percentage of events with ICC assigned	99.4%	99.4%	99.0%	99.2%	100.0%	99.4%
Transmission severity all TADS events	643.8	675.8	665.7	612.4	506.0	3,103.7
Transmission severity of events with ICC assigned	636.8	667.5	654.6	602.1	506.0	3,066.9
Percentage of Transmission severity of events with ICC assigned	98.9%	98.8%	98.3%	98.3%	100.0%	98.8%

For TADS events initiated by a common cause, the probability[92] of observing that the event initiates during a given hour is estimated using the corresponding event occurrences reported in TADS. Namely, the probability of the occurrence of the event is the total number of a given type of event during the study period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities for all events is equal to the estimated probability of any event during a given hour. With the development of the transmission severity measure and TADS event ICCs, it is possible to statistically analyze the most recent five years of TADS data (2009–2013). The analysis shows which ICCs result in the highest transmission severity and finds statistically significant changes in transmission severity by ICC over time.

[91] For detailed definitions of TADS cause codes, please refer to: http://www.nerc.com/pa/RAPA/tads/Transmission Availability Data System Working Group/TADS Definitions (Appendix 7).pdf, January 14, 2013, pp. 19-20.

[92] Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration.

Determining Relative Risk

Each study followed a similar approach, as shown in Figure A.2. Each study was performed to determine the correlation between each ICC and transmission severity, and whether a statistically significant confidence level was 95 percent or higher. Then, sample distributions were studied to determine any statistically significant pair-wise differences in expected transmission severity between ICCs, including a time trend analysis where applicable. Finally, the relative risk was calculated for each ICC group.

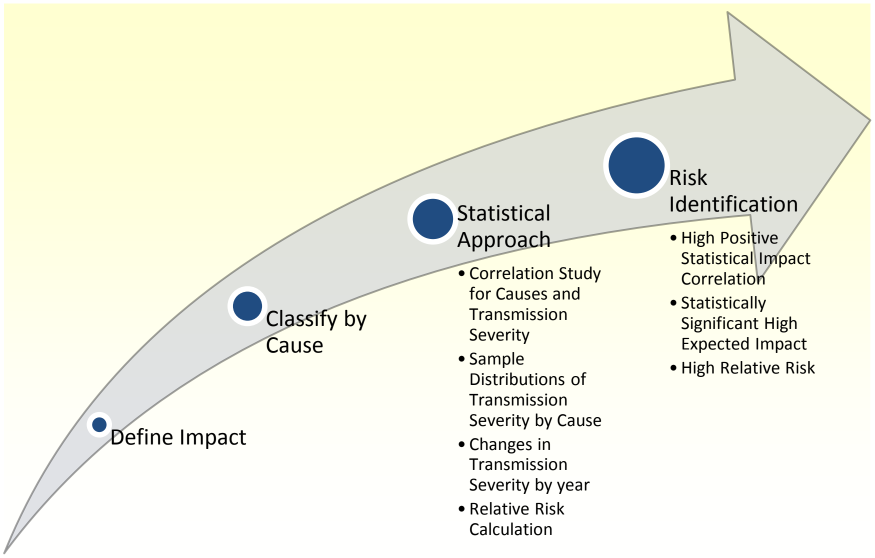

Figure A.2: Risk Identification Method

To study the relationship between ICCs and the transmission severity of TADS events, NERC investigated the statistical significance of the correlation between transmission severity and the indicator function[93] of a given ICC.[94] The test is able to determine a statistically significant positive or negative correlation between ICC and transmission severity.

Distributions of transmission severity for the entire dataset were examined separately for events with a given ICC. A series of t-tests[95] were performed to compare the expected transmission severity of a given ICC with the expected severity of the rest of the events at significance level of 0.05. Then, the Fisher's Least Square[96] difference method was applied to determine statistically significant[97] differences in the expected transmission severity for all pairs of ICCs.

Where applicable, a time trend analysis was performed. Statistically significant differences in the expected transmission severity for each ICC group were analyzed for each year of data. This showed if the average transmission severity for a given ICC group had changed over time.

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[93] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[94] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission severity.

[95] For t-test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 361-369.

[96] For Fisher's Least Significance Difference (LSD) method or test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 524-526.

[97] At significance level of 0.05.

Finally, relative risk was calculated for each ICC group. The impact of an outage event was defined as the expected transmission severity associated with a particular ICC group. The probability that an event from a given group initiates during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. The risk per hour of a given ICC was calculated as the product of the probability per hour and the expected severity (impact) of an event from this group. The relative risk was then defined as the percentage of the risk associated with each ICC out of the total (combined for all ICC events) risk per hour.

Table A.3 lists annual counts and hourly event probability of TADS events by ICC.[98] The three ICCs with the largest number of events are weather (with and without lightning), Unknown, and a group defined as Reliability Metrics (composed of ICCs of Human Error, Failed AC Circuit Equipment, Failed AC Substation Equipment, and Failed Protection System Equipment). The four ICCs grouped as Reliability Metrics are related to ALR6-12, ALR6-14, ALR6-13 and ALR6-11 and are combined in one section of the table. Metrics are provided for each of the ICCs in the group, as well as for the group as a whole.

Almost all TADS ICC groups have sufficient data available to be used in a statistical analysis. Only four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental; and Failed AC/DC Terminal Equipment) do not have enough observations. These are combined into a new group, named “Combined Smaller ICC Groups,” that can be statistically compared to every other group and also studied with respect to annual changes of transmission severity.

Table A.3: TADS Events and Hourly Event Probability by ICC

Initiating Cause Code	2009	2010	2011	2012	2013	2009–2013	Event Probability/Hour
Reliability Metrics	**1043**	**1054**	**1120**	**1042**	**908**	**5167**	**0.1179**
Human Error	291	305	291	307	280	1474	**0.0336**
Failed AC Circuit Equipment	257	277	306	261	248	1349	**0.0308**
Failed AC Substation Equipment	266	238	289	248	192	1233	**0.0281**
Failed Protection System Equipment	229	234	234	226	188	1111	**0.0254**
Lightning	789	741	822	852	814	4018	**0.0917**
Unknown	673	821	782	710	712	3698	**0.0844**
Weather Excluding Lightning	534	673	539	446	434	2626	**0.0599**
Foreign Interference	199	173	170	170	181	893	**0.0204**
Contamination	96	145	132	160	152	685	**0.0156**
Power System Condition	112	74	121	77	109	493	**0.0112**
Other	107	84	91	104	64	450	**0.0103**
Fire	92	84	63	106	130	475	**0.0108**
Combined Smaller ICC groups	**39**	**46**	**54**	**57**	**53**	**249**	**0.0057**
Vegetation	29	27	44	43	36	179	**0.0041**
Vandalism, Terrorism, or Malicious Acts	4	6	5	10	9	34	**0.0008**
Environmental	5	11	5	4	8	33	**0.0008**
Failed AC/DC Terminal Equipment	1	2	0	0	0	3	**0.0001**
All TADS events	**3705**	**3917**	**3934**	**3753**	**3557**	**18866**	**0.4305**
All with ICC assigned	**3684**	**3895**	**3894**	**3724**	**3557**	**18754**	**0.4279**

[98] For detailed definitions of TADS cause codes, please refer to: http://www.nerc.com/pa/RAPA/tads/Transmission Availability Data System Working Grou/TADS Definitions (Appendix 7).pdf, January 14, 2013, pp. 19-20.

Correlation between ICC and Transmission Severity

Figure A.3 shows the correlations between calculated transmission severity and the given ICC. To study a relationship between ICC and transmission severity of TADS events, the statistical significance of the correlation between transmission severity and the indicator function[99] of a given ICC was investigated.[100] A statistically significant positive or negative correlation between ICC and transmission severity could be determined by the test. A statistically significant positive correlation of ICC to transmission outage severity would indicate a greater likelihood that an event with this ICC would result in a higher transmission outage severity. A stark negative correlation would indicate the contrary; in this case, a lower transmission outage severity would be likely. If no significant correlation is found, it indicates the absence of a linear relationship between ICC and the transmission outage severity, and that the events with this ICC have an expected transmission severity similar to all other events from the database.

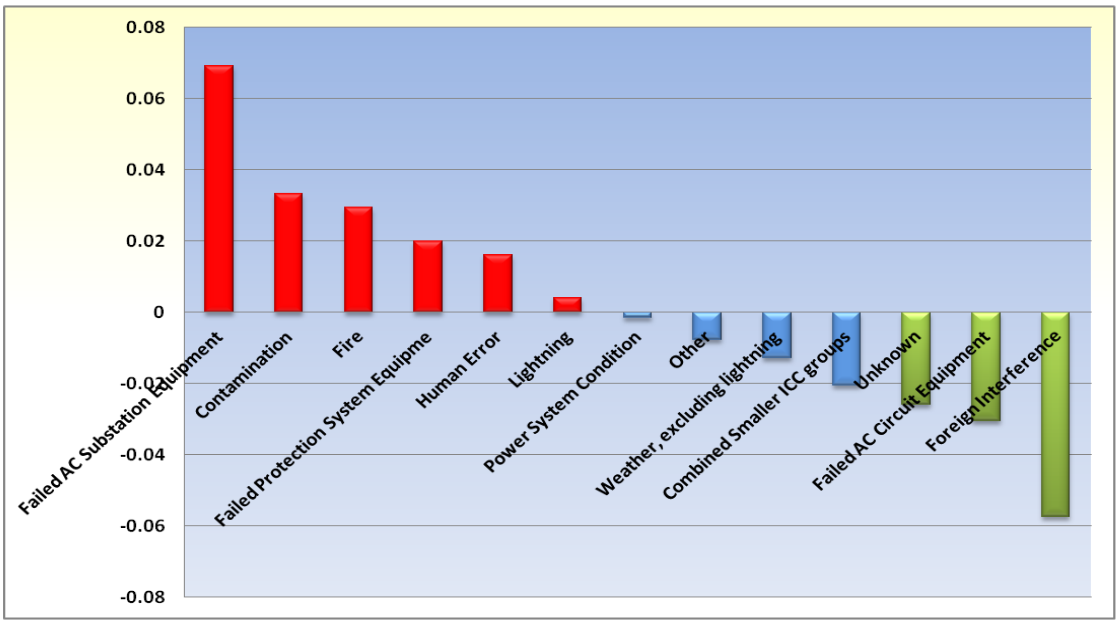

Figure A.3: Correlation between Augmented ICC and TS of TADS Events (2012–2013)

There were three key outcomes of all the tests. To begin, Failed AC Substation Equipment, Contamination, Fire, Reliability Metrics, Human Error, and Failed Protection System Equipment have statistically significant positive correlation with transmission severity. The expected severity of events with each of these ICCs is greater than the expected severity compared to other ICC events. Secondly, Foreign Interference, Failed AC Circuit Equipment, Smaller ICC Groups Combined, Unknown, and Weather Excluding Lightning have a statistically significant negative correlation with transmission severity. The expected severity of events initiated by these causes is smaller than the expected transmission severity of the remaining dataset. Finally, for each of the remaining groups (Power System Condition, Lighting, Other), the difference between transmission severity for the group and for its complement is not statistically significant.

Distribution of Transmission Severity by ICC

Next, the distribution of transmission severity for the entire dataset was studied separately for events with a given ICC. The transmission severity of the 2009–2013 dataset has a sample mean of 0.165 and the sample standard deviation of 0.108. The sample statistics for transmission severity by ICC are listed in Table A.4.

[99] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[100] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission severity.

The groups of events initiated by Failed AC Substation Equipment, Fire, and Failed Protection System Equipment not only have statistically[101] greater expected severity than the rest of the events, but the variance of transmission severity (and its standard deviation) for each of these groups is also statistically greater than the variance for the other events. The greater variance is an additional risk factor since it indicates more frequent occurrences of events with high transmission severity.

Table A.4 provides a column that indicates which other ICCs are statistically smaller than a given ICC referenced by the table's column 1 index. For example, transmission severity for Human Error (#5) is significantly smaller than for Failed AC Substation Equipment (#1), while Fire (#2) is not statistically significantly smaller than Failed AC Substation Equipment.

Table A.4: Distribution of Transmission Severity by ICC (2009–2013)

#	Initiating Cause Code	Average TS of Events with the ICC	Is Expected TS Statistically Significantly Bigger than for the Rest of the Events with ICC Assigned?	ICC with Statistically Significantly Smaller TS	Standard Deviation of TS
1	Failed AC Substation Equipment	0.191	Yes	3,4,5,6,7,8,9,10,11,12,13	0.135
2	Fire	0.183	Yes	5,6,7,8,9,10,11,12,13	0.131
3	Contamination	0.182	Yes	5,6,7,8,9,10,11,12,13	0.107
4	Failed Protection System Equipment	0.172	Yes	8,9,10,11,12,13	0.123
5	Human Error	0.169	Yes	8,10,11,12,13	0.102
6	Lightning	0.164	No	10,11,12,13	0.095
	All TADS events	**0.165**	**N/A**	**N/A**	**0.108**
	All with ICC assigned	**0.164**	**N/A**	**N/A**	**0.106**
7	Power System Condition	0.163	No	12,13	0.185
8	Weather Excluding Lightning	0.160	No	11,12,13	0.095
9	Other	0.158	No	13	0.216
1	Unknown	0.158	No	11,12,13	0.078
1	Failed AC Circuit Equipment	0.152	No	13	0.086
1	Combined Smaller ICC groups	0.144	No	none	0.132
1	Foreign Interference	0.136	No	none	0.065

[101] At significance level 0.05

Average Transmission Severity by ICC: Annual Changes

Year-over-year changes in calculated transmission severity by ICC were reviewed next. Figure A.4 shows changes in the average severity for each ICC and for the 2009–2013 dataset. The groups of ICC events are listed from left to right by descending average transmission severity for the five-year data. The largest average transmission severity over the five-year period was observed for events initiated by Failed AC Substation Equipment; the single-highest annual average transmission severity is observed for 2010 events initiated by Fire. NERC's investigation revealed that two wildfires[102] initiated the most severe events in this category.

It should be noted that for all ICC groups except Power System Condition, Combined Smaller ICC Groups, and Foreign Interference, the 2013 average transmission severity reduced compared with 2012; and for all groups except Power System Condition, it stayed below the five-year average transmission severity of the group.

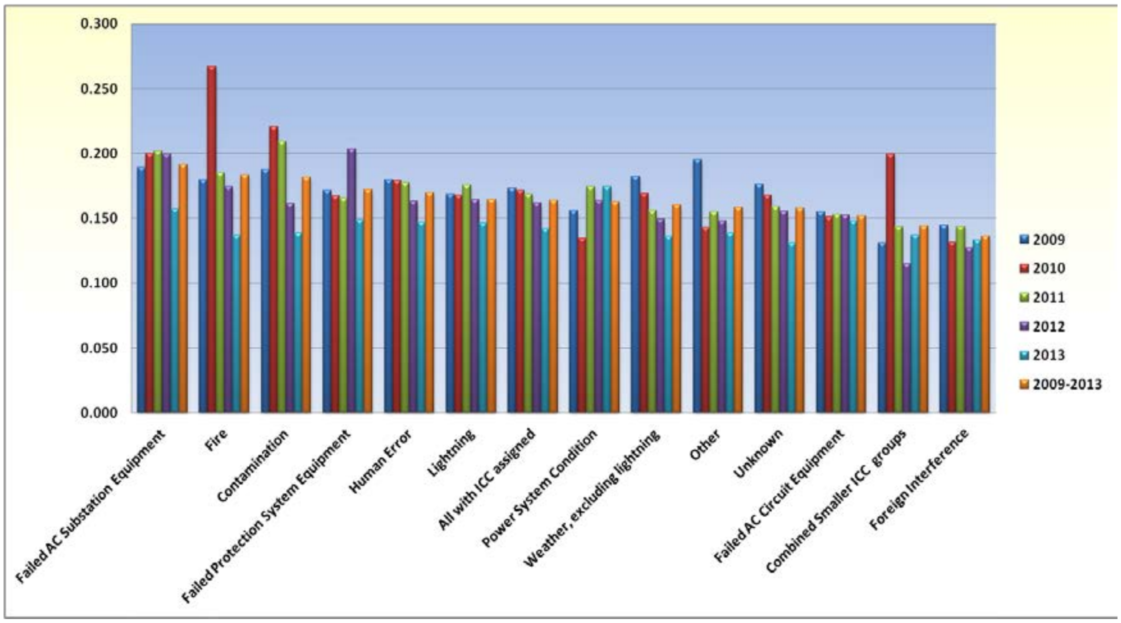

Figure A.4: Average Transmission Severity of TADS Events by ICC (2009–2013)

The following series of graphs shows changes in the average transmission severity by year for four groups of ICCs. For each group, the graph is accompanid by a list of statistically significant[103] changes (decreases and increases).

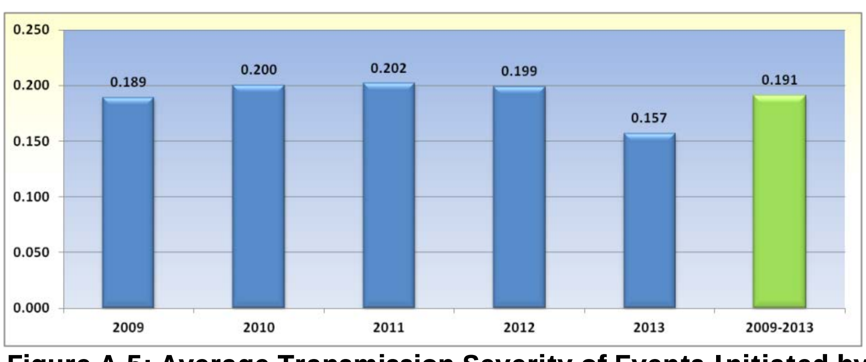

Figure A.5: Average Transmission Severity of Events Initiated by Failed AC Substation Equipment (2009–2013)

- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - 2009 vs. 2013
  - 2010 vs. 2013
  - 2011 vs. 2013
  - 2012 vs. 2013

[102] Québec wildfires June 22-23, 2010, and Sequoia National Forest fire in California, July 29-30, 2010

[103] This summary only lists changes that are statistically significant at the 0.05 level.

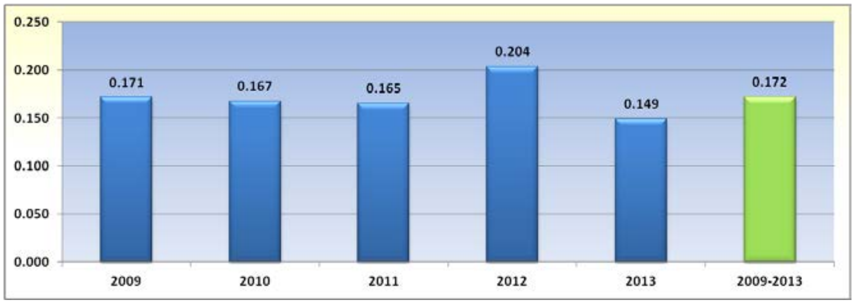

Figure A.6: Average Transmission Severity of Events Initiated by Failed Protection System Equipment (2009–2013)

- Statistically significant year-over-year increases
  - 2009 vs. 2012
  - 2010 vs. 2012
  - 2011 vs. 2012
- Statistically significant year-over-year decreases
  - 2012 vs. 2013

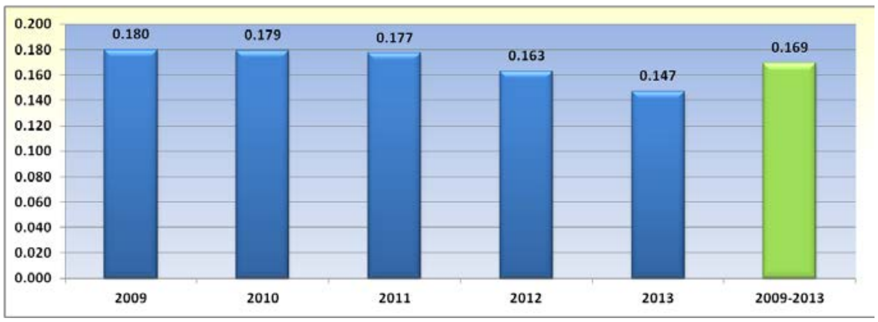

Figure A.7: Average Transmission Severity of Events Initiated by Human Error (2009–2013)

- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - 2009 vs. 2012
  - 2009 vs. 2013
  - 2010 vs. 2012
  - 2010 vs. 2013
  - 2011 vs. 2013

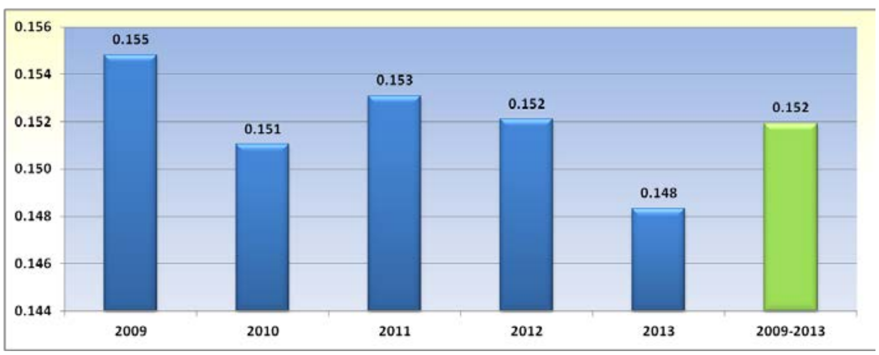

Figure A.8: Average Transmission Severity of Events Initiated by Failed AC Circuit Equipment (2009–2013)

- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - none

Finally, for the 2008–2012 set of TADS events, changes in the average transmission severity by year are as follows:

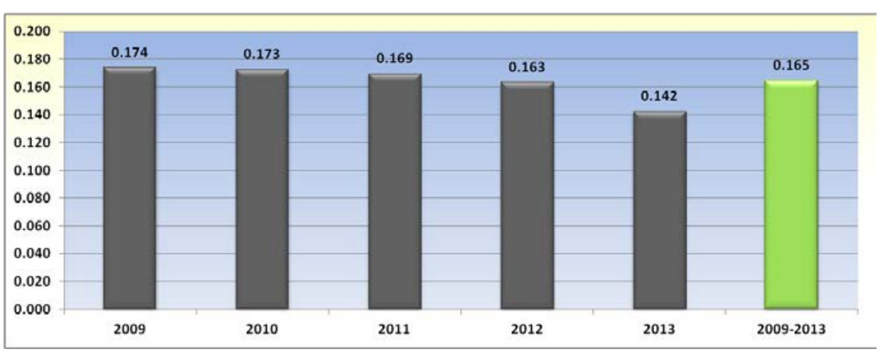

Figure A.9: Average Transmission Severity of TADS Events (2009–2013)

- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - 2009 vs. 2012
  - 2010 vs. 2012
  - 2010 vs. 2013
  - 2011 vs. 2012
  - 2011 vs. 2013
  - 2012 vs. 2013

Total (Combined) Transmission Severity by ICC: Annual Changes

Total annual transmission severity associated with each ICC by year (the sum of the transmission severity of all events from the group) is listed in Table A.5.

Table A.5: Annual Transmission Severity by ICC (2009–2013)					
Group of TADS events	**2009**	**2010**	**2011**	**2012**	**2013**
Reliability Metrics	**181.7**	**183.2**	**195.4**	**185.1**	**136.1**
Human Error	52.3	54.7	51.5	50.0	41.2
Failed AC Circuit Equipment	39.8	41.8	46.8	39.7	36.8
Failed AC Substation Equipment	50.4	47.6	58.3	49.3	30.2
Failed Protection System Equipment	39.3	39.1	38.7	46.0	28.0
Lightning	132.7	124.4	144.5	139.8	119.1
Unknown	118.4	137.9	124.2	110.2	93.4
Weather Excluding Lightning	97.2	113.6	83.9	66.6	59.3
Foreign Interference	28.8	22.7	24.4	21.6	24.1
Contamination	18.0	32.0	27.6	25.8	21.0
Power System Condition	17.4	10.0	21.1	12.6	19.0
Fire	16.5	22.4	11.7	18.5	17.8
Other	20.9	12.0	14.1	15.4	8.9
Combined Smaller ICC Groups	**5.1**	**9.2**	**7.8**	**6.5**	**7.3**
All TADS Events	**643.8**	**675.8**	**665.7**	**612.4**	**506.0**
All with ICC Assigned	**636.8**	**667.5**	**654.6**	**602.1**	**506.0**

Figure A.10 shows changes in the total transmission severity of TADS events by year.

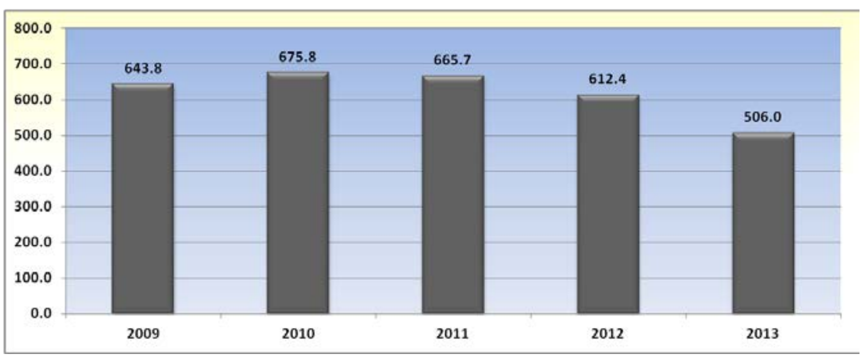

Figure A.10: Total Transmission Severity of TADS Events (2009–2013)

- Statistically significant year-over-year increases
  - none
- Statistically significant year-over-year decreases
  - 2010 vs. 2012
  - 2010 vs. 2013
  - 2011 vs. 2012
  - 2011 vs. 2013
  - 2012 vs. 2013

In particular, changes in the total transmission severity of events with a common ICC related to one of the ALR metrics are shown in Figure A.11.

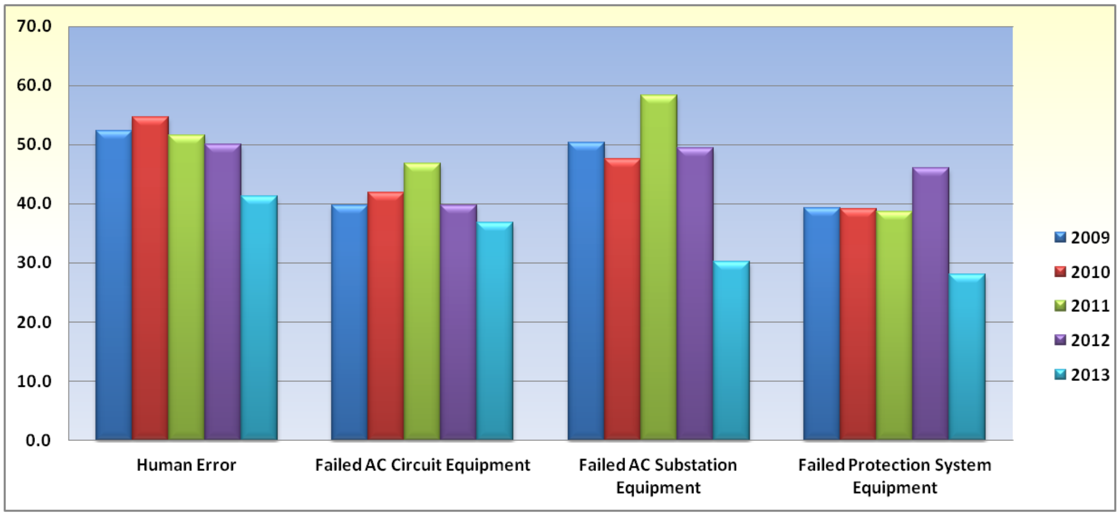

Figure A.11: Total Transmission Severity by Year

There were several statistically significant increases and decreases over time for ICCs related to Adequate Level of Reliability (ALR) metrics, as summarized below. For the annual total transmission severity of TADS events initiated by Human Error, there were:

- no statistically significant increases;
- statistically significant year-over-year decreases:
  - 2009 vs. 2013
  - 2010 vs. 2012
  - 2010 vs. 2013
  - 2011 vs. 2013

For the annual total transmission severity of TADS events initiated by Failed AC Circuit Equipment, there were:

- no statistically significant changes

For the annual total transmission severity of TADS events initiated by Failed AC Substation Equipment, there were:

- no statistically significant increases;
- statistically significant year-over-year decreases:
  - 2009 vs. 2013
  - 2010 vs. 2013
  - 2011 vs. 2013
  - 2012 vs. 2013

For the annual total transmission severity of TADS events initiated by Failed Protection System Equipment, there were:

- statistically significant year-over-year increases:
  - 2009 vs. 2012

- 2011 vs. 2012
- statistically significant year-over-year decreases:
  - 2012 vs. 2013.

Thus, all groups of TADS events from Reliability Metrics had a reduction in their total transmission severity in 2013 as compared with any other year from 2009 to 2012; moreover, many of these reductions were statistically significant.

Transmission Severity Risk and Relative Risk of TADS Events by ICC

The risk of each ICC group can be defined as the total transmission severity associated with this group; its relative risk is equal to the percentage of the group transmission severity in the 2009–2013 database. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability that an event with this ICC initiates during an hour and the expected severity (impact) of an event from this group. For any ICC group, the relative risk per hour is the same as the relative risk for five years (or any other time period). Figure A.12 shows year-over-year changes in the relative risk of TADS events by ICC.

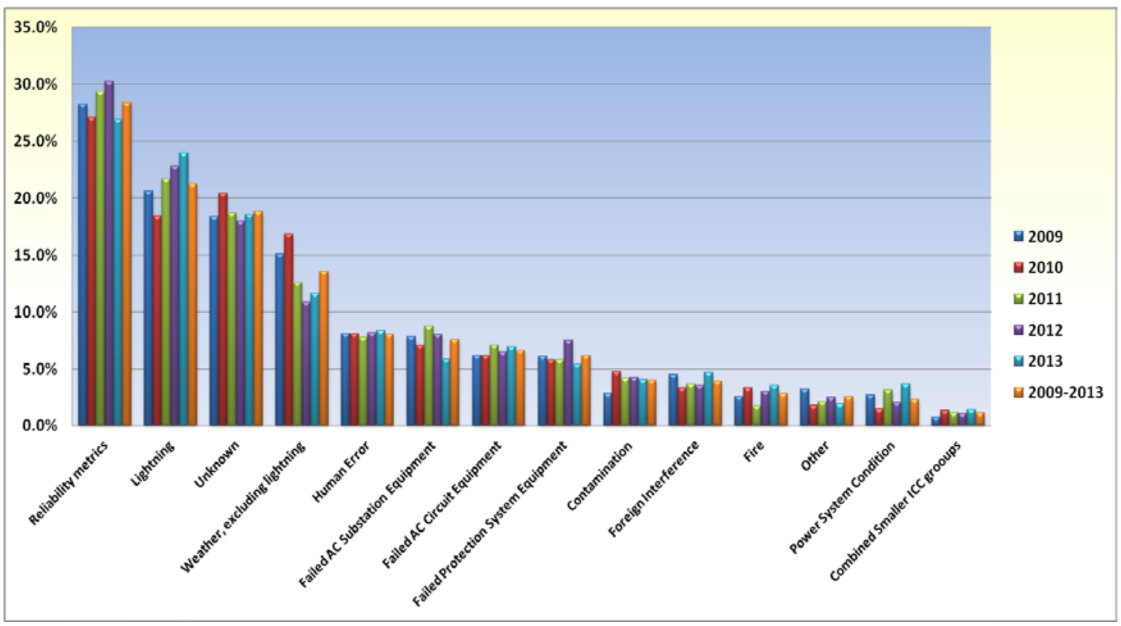

Figure A.12: Relative Transmission Severity Risk by ICC and Year

2012–2013 Study with Augmented Event Types

TOs provided transmission performance information using the NERC TADS process. The data used in these studies includes momentary and sustained automatic outages of ac transmission circuits (overhead and underground) that operate at voltages greater than or equal to 200 kV.

TADS event-type reporting was modified in 2012 to further distinguish normal clearing events from abnormal clearing events. To introduce the additional data into this study where this level of detail is not available for prior years, TADS events with protection system misoperations—event types 61 dependability[104] (failure to operate)

[104] Event Type 61 Dependability (failure to operate): one or more automatic outages with delayed fault clearing due to failure of a single protection system (primary or secondary backup) under either of these conditions:

- Failure to initiate the isolation of a faulted power system Element as designed, or within its designed operating time, or
- In the absence of a fault, failure to operate as intended within its designed operating time.

and 62 security[105] (unintended operation)—are included with ICCs as shown in Table A.6. The new ICCs developed are analogous to protection system misoperations, which are comprised of Failed Protection System Equipment (FPSE) and Human Error with event type 61 or 62 (HE and Type 61/62). Aggregate totals of 2012–2013 TADS events by augmented ICC are provided in Table A.6. Events initiated by Misoperations comprise 8.2 percent of all events and represent the fourth-largest group of events (after weather-related and Unknown ICCs.)

Table A.6: TADS Outage Events by Augmented ICC (2012-2013)

Initiating Cause Code	2012	2013	2012-2013
Lightning	852	813	1665
Unknown	710	712	1422
Weather Excluding Lightning	446	433	879
Misoperation: FPSE OR (HE AND Type 61/62)	321	281	602
Failed AC Circuit Equipment	261	248	509
Failed AC Substation Equipment	248	191	439
Human Error AND NOT(Type 61 OR Type 62)	212	191	403
Foreign Interference	170	181	351
Contamination	160	151	311
Fire	106	130	236
Power System Condition	77	109	186
Other	104	64	168
Vegetation	43	36	79
Vandalism, Terrorism, or Malicious Acts	10	9	19
Environmental	4	8	12
All with ICC assigned	**3724**	**3557**	**7281**
In TADS	**3753**	**3557**	**7310**

Human Error ICCs with event type 61 or 62 correspond to two misoperation causes:[106] incorrect setting/logic/design error or as-left personnel error. These ICCs also include Human Error events that occur during maintenance and testing activities that would not traditionally be classified as a misoperation. Historically, Human Error events during maintenance and testing that results in protection system activation have contributed to large disturbance events. Therefore, these events were included to capture this risk. After reclassifying 184 events that were initially identified as Human Performance but were reclassified as Misoperations, Human Error now accounts for 5.5 percent of all 2012–2013 TADS events.

[105] Event Type 62 Security (unintended operation): one or more automatic outages caused by improper operation (e.g., overtrip) of a protection system resulting in isolating one or more TADS elements it is not intended to isolate, either during a fault or in the absence of a fault.

[106] http://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%20DL/Protection_System_Misoperation_Reporting_Template_Final.xlsx, January 16, 2013.

Figure A.13 shows the correlation between calculated transmission severity and each ICC. A red bar in Figure A.13 corresponds to an ICC that has a statistically significant positive correlation with transmission severity, a green bar corresponds to an ICC that has a statistically significant negative correlation, and a blue bar corresponds to an ICC that has a correlation that is not statistically significant. A statistically significant positive correlation of an ICC with a transmission outage severity would indicate a higher likelihood that an event with that ICC will result in a higher transmission outage severity. A statistically significant negative correlation indicates the contrary; in this case, a lower transmission outage severity would be likely. If a correlation is not statistically significant, this implies that a positive or negative correlation was very likely observed by a mere chance, and there is, in fact, no relationship between ICC and the transmission outage severity. The events with this ICC have an expected transmission severity similar to all other events from the database.

Failed AC Substation Equipment and Misoperations had the largest and most statistically significant positive correlation with 2012–2013 automatic transmission outage severity. In other words, TADS events initiated by these two causes tended to have higher transmission severity than other TADS events that occurred in 2012 and 2013.

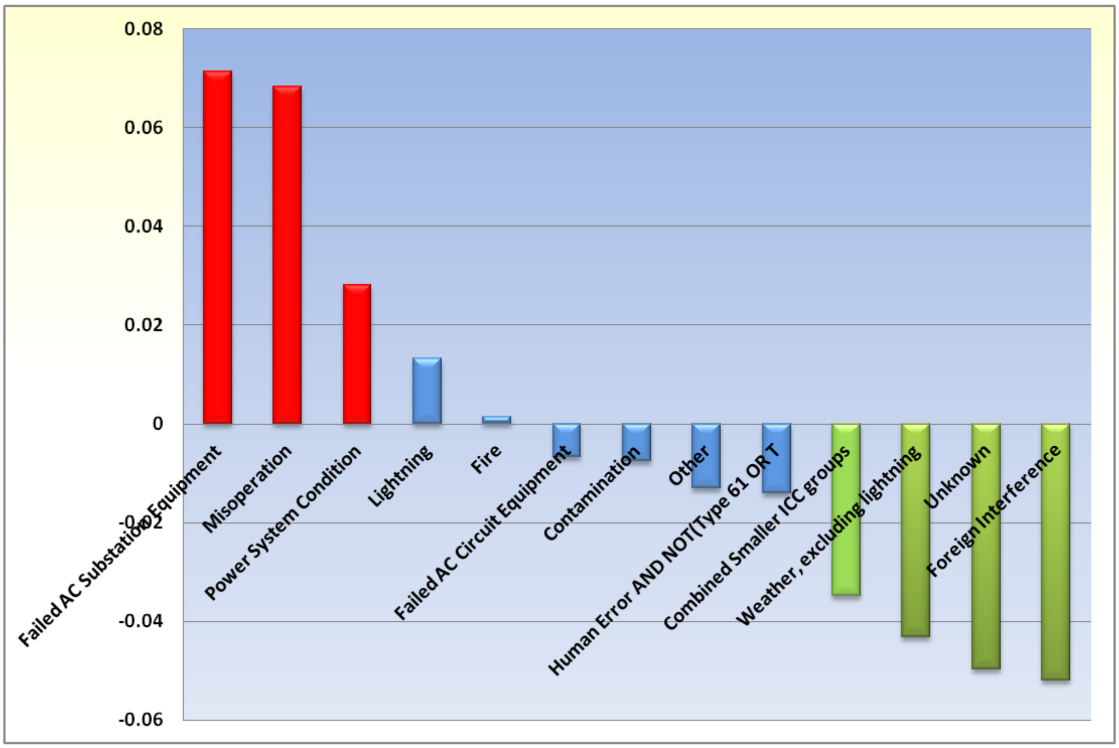

Figure A.13: Correlation between Augmented ICC and TS of TADS Events (2012–2013)

Relative risk of the 2012–2013 TADS events by augmented ICC is listed in Table A.7. The probability that an event from a given group initiated during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. Excluding weather-related and Unknown events, events initiated by Misoperations and by Failed AC Substation Equipment had the largest shares in the total transmission severity and contributed 9.4 and 7.1 percent, respectively, to transmission severity relative risk.

Table A.7: Relative Risk by Augmented ICC (2012–2013)

Group of TADS events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected Transmission Severity of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group (%)
Lightning	0.095	0.155	0.015	**23.1**
Unknown	0.081	0.143	0.012	**18.2**
Weather Excluding Lightning	0.050	0.143	0.007	**11.2**
Misoperation	0.034	0.175	0.006	**9.4**
Failed AC Substation Equipment	0.025	0.180	0.005	**7.1**
Failed AC Circuit Equipment	0.029	0.151	0.004	**6.9**
Human Error AND NOT(Type 61 OR Type 62)	0.023	0.150	0.003	**5.4**
Contamination	0.018	0.149	0.003	**4.2**
Foreign Interference	0.020	0.130	0.003	**4.1**
Fire	0.013	0.154	0.002	**3.2**
Power System Condition	0.011	0.170	0.002	**2.8**
Other	0.010	0.145	0.001	**2.2**
Combined Smaller ICC groups	**0.006**	**0.126**	**0.001**	**1.2**
All TADS events	**0.417**	**0.153**	**0.064**	**100.0**
All with ICC assigned	**0.415**	**0.152**	**0.063**	**99.1**

Since additional outage detail is available for two years, annual changes in transmission severity of the events initiated by Misoperations can now be studied. The analysis is provided in Table A.8. Statistical tests led to the conclusion that both the average transmission severity of these events and their total transmission severity statistically significantly decreased in 2013 versus 2012.

Table A.8: Relative Risk by Augmented ICC (2012–2013)

TADS events initiated by Misoperations	2012	2013
Average TS of an event	0.198	0.149
Total TS of the group	63.6	41.8

CDM Events: Definitions and Breakdown by ICC

As part of the analysis, a breakdown of ICCs was performed for TADS events containing Common- or Dependent-Mode (CDM) outages. These TADS events have more transmission severity than TADS events with a Single-Mode outage. TADS events were separated into two types: Single-Mode events and CDM events. A Single-Mode event is defined as a TADS event with a single-element outage. A CDM TADS event is a TADS event in which all outages have one of the modes (other than Single Mode) in Table A.9.

Table A.9: Outage Mode Codes

Outage Mode Code	Automatic Outage Description
Single Mode	A single-element outage that occurs independently of another automatic outage
Dependent Mode Initiating	A single-element outage that initiates at least one subsequent element automatic outage
Dependent Mode	An automatic outage of an element that occurred as a result of an initiating outage, whether the initiating outage was an element outage or a non-element outage
Common Mode	One of at least two automatic outages with the same ICC where the outages are not consequences of each other and occur nearly simultaneously
Common Mode Initiating	A common-mode outage that initiates one or more subsequent automatic outages

Some TADS events were entered as a combination of Single-Mode outages and other outage modes. These events were manually examined to determine if the event was Single-Mode or CDM. For some events, it was not possible to determine whether the event was Single-Mode or CDM, nor was it possible to tell the ICC for the event. These events, approximately 0.4 percent of all TADS events, were removed from the study.

Table A.10 lists CDM events by ICC in the 2009–2013 database and their percentages with respect to all TADS events with a given ICC. Similar to all TADS events, Lightning initiated the largest number of CDM events. CDM events initiated by Failed AC Substation Equipment comprise the second largest group, followed by Weather Excluding Lightning, and Human Error. Overall, 3,227 CDM events were defined, representing 17.1 percent of all TADS events from 2009 to 2013. Out of these, 3,136 are assigned to one of the 17 ICCs.

Almost all ICC groups of CDM events for five years have a sufficient sample size to be used in a statistical analysis, but the sample size is not enough to track statistically significant year-over-year changes in transmission severity. Four ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; Environmental, and Failed AC/DC Terminal Equipment) must be combined to comprise a new group, Combined Smaller ICC Groups, that can be statistically compared to every other group.

Table A.10: CDM Events and Hourly Event Probability by ICC (2009–2013)

Initiating Cause Code	ALL TADS events	CDM events	CDM as % of ALL	Event Probability/Hour
Reliability Metrics	**5167**	**1249**	**24.2**	**0.0285**
Failed AC Substation Equipment	1233	444	36.0	0.0101
Failed Protection System Equipment	1111	296	26.6	0.0068
Human Error	1474	324	22.0	0.0074
Failed AC Circuit Equipment	1349	185	13.7	0.0042
Lightning	4018	559	13.9	0.0128
Weather Excluding Lightning	2626	334	12.7	0.0076
Unknown	3698	306	8.3	0.0070
Power System Condition	493	310	62.9	0.0071
Other	450	109	24.2	0.0025
Foreign Interference	893	97	10.9	0.0022
Fire	475	77	16.2	0.0018
Contamination	685	59	8.6	0.0013
Combined Smaller ICC groups	**249**	**36**	**14.5**	**0.0008**
Vegetation	179	14	7.8	0.0003
Environmental	33	11	33.3	0.0003
Failed AC/DC Terminal Equipment	3	3	100.0	0.0001
Vandalism, Terrorism, or Malicious	34	8	23.5	0.0002
All In TADS	**18866**	**3227**	**17.1**	**0.0736**
All with ICC assigned	**18754**	**3136**	**16.7**	**0.0716**

CDM Events: Correlation between ICC and Transmission Severity

To study a relationship between ICC and transmission severity of TADS events, the statistical significance of the correlation between transmission severity and the indicator function[107] of a given ICC was investigated.[108] A statistically significant positive or negative correlation between ICC and transmission severity could be determined by the test.

A red bar in Figure A.14 corresponds to an ICC that has a statistically significant positive correlation with transmission severity, a green bar corresponds to an ICC that has a statistically significant negative correlation, and a blue bar corresponds to an ICC is not statistically significant. A statistically significant positive correlation of initiating cause code with transmission outage severity would indicate a higher likelihood that an event with this ICC will result in a higher transmission outage severity. A statistically significant negative correlation indicates the contrary; in this case, a lower transmission outage severity would be likely. If a correlation is not statistically significant, this implies that a positive or negative correlation was very likely observed by a mere chance, and there is, in fact, no linear relationship between ICC and the transmission outage severity, and the events with this ICC have the expected transmission severity similar to all other events from the database.

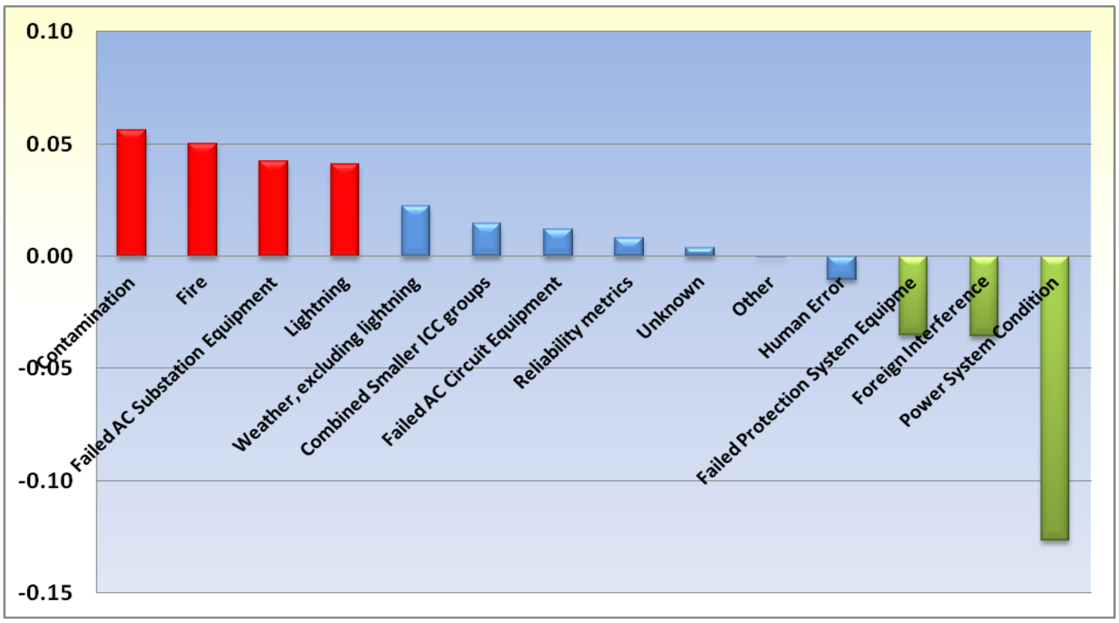

Figure A.14: Correlation between ICC and TS of TADS CDM Events (2009-2013)

Results of the correlation analysis are as follows:

- For the 2009–2013 CDM events, the Contamination ICC has the largest and most statistically significant positive correlation with transmission severity, followed by Fire and Failed AC Substation Equipment. Lightning also has a statistically significant positive correlation.
- Power System Condition, Foreign Interference, and Failed Protection System Equipment have a statistically significant negative correlation with transmission severity. CDM events initiated by either of these causes, on average, tend to have a smaller severity than events from the entire CDM dataset.

[107] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[108] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission severity.

CDM Events: Distribution of Transmission Severity by ICC

Next, the distribution of transmission severity for CDM events with a given ICC was studied. The transmission severity for CDM events has a sample mean of 0.244 and a sample standard deviation of 0.187. The sample statistics for transmission severity by ICC are listed in Table A.11. The CDM events initiated by Contamination have the largest average transmission severity of 0.317, followed by Fire and Failed AC Substation Equipment (with the expected transmission severity of 0.300, 0.261, respectively). The events initiated by Power System Condition have the smallest average severity of 0.170. Interestingly, the CDM events initiated by Contamination and Fire did not occur often, but upon occurrence resulted in significant transmission severity. Because CDM events typically have more outages per event than Single-Mode events, on average CDM events have higher transmission severity than TADS events.

Table A.11 provides a column that indicates which other ICCs are statistically smaller than a given ICC referenced by the table's column 1 index. For example, transmission severity for Unknown (#8) is statistically significantly smaller than Contamination (#1), while Fire (#2) is not statistically significantly smaller than Contamination.

Transmission Severity Risk and Relative Risk of CDM Events by ICC

If the transmission severity risk of each ICC group is simply the total transmission severity associated with the group, then its relative risk is equal to the percentage of the group transmission severity in the 2009–2013 dataset. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability that an event with this ICC initiated during an hour and the expected severity, or impact, of an event from this group. Then, for any ICC group, the relative risk per hour is the same as the relative risk for five years or any other time period. Table A.11 lists relative risk by ICC with the ICC groups of CDM events in order from the largest relative risk to the smallest.

Table A.11: Evaluation of CDM Event ICC Contribution to Transmission Severity (2009–2013)

Group of TADS events	Probability that an Event from a Group Starts during a Given Hour	Expected Impact (Expected Transmission Severity of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group (%)
CDM Lightning	0.013	0.258	0.003	4.6
CDM Failed AC Substation Equipment	0.010	0.261	0.003	3.7
CDM Weather Excluding Lightning	0.008	0.253	0.002	2.7
CDM Human Error	0.007	0.236	0.002	2.5
CDM Unknown	0.007	0.244	0.002	2.4
CDM Failed Protection System Equipment	0.007	0.221	0.001	2.1
CDM Power System Condition	0.007	0.170	0.001	1.7
CDM Failed AC Circuit Equipment	0.004	0.250	0.001	1.5
CDM Other	0.002	0.241	0.001	0.8
CDM Fire	0.002	0.300	0.001	0.7
CDM Foreign Interference	0.002	0.204	0.000	0.6
CDM Contamination	0.001	0.317	0.000	0.6
CDM Combined Smaller ICC groups	0.001	0.257	0.000	0.3
All TADS events	**0.430**	**0.165**	**0.071**	**100.0**
All CDM events	**0.074**	**0.244**	**0.018**	**25.4**
All with ICC assigned	**0.072**	**0.241**	**0.017**	**24.4**

Appendix B – Statistical Analysis for ALR1-12 Metric

Interconnection Frequency Response: Time Trends

Eastern Interconnection

The time trend analysis uses the Eastern Interconnection frequency response (FR) datasets for 2009–2013. In this section, relationships between frequency response and the explanatory variable T (time: year, month, day, hour, minute, second) are studied.

Even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a negative slope at -0.07139, the linear regression is not statistically significant[109] and, on average, the Eastern Interconnection frequency response[110] has been stable from 2009 through 2013.

ERCOT Interconnection

The time trend analysis uses the ERCOT frequency response datasets for 2009–2013. In this section, the relationship is investigated between frequency response and the explanatory variable T, when a frequency response event happened.

There is a positive correlation of 0.23 between T and FR; further, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) results in a rejection of the null hypothesis about zero correlation (p-value of both tests below 0.0001). This proves that it was very unlikely that the observed positive correlation occurred simply by chance. Moreover, a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a statistically significant positive slope (0.0000013), the linear regression is statistically significant, and on average, the ERCOT Interconnection frequency response increased from 2009 through 2013 at the average rate of 3.3 MW/.1 Hz.

Québec Interconnection

The time trend analysis uses the Québec Interconnection frequency response datasets for 2011–2013. The frequency response values represent the observed values of the analysis (response) variable FR of the Québec Interconnection frequency response. In this section, the relationship is investigated between frequency response and the explanatory variable T, when a frequency response event happened.

There is a positive correlation of 0.13 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p-value of the both tests is 0.23). This result leads to the conclusion that with high probability the positive correlation could occur simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a positive slope (0.00000104), the linear regression is not statistically significant, and on average, the Québec Interconnection frequency response has been stable from 2011 through 2013.

Western Interconnection

The time trend analysis uses the Western Interconnection frequency response datasets from 2009 through 2013. The frequency response values represent the observed values of the analysis (response) variable FR, the Western Interconnection frequency response. In this section, the relationship is investigated between FR and the explanatory variable T, when a frequency response event happened.

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[109] The linear regression in http://www.nerc.com/docs/standards/dt/Field_Trial_Analysis-final_20120910.pdf recommended by Howard Ilian is completely different from the linear regression in Appendix B which is used for time trend analysis.

[110] There is a positive correlation of 0.0017 between T and FR; however, the statistical test on significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p-value of the both tests is 0.98). This implies the increase in the expected frequency response since 2009 could just be chance.

There is a negative correlation of -0.05 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p value of the both tests is 0.60). This result leads to the conclusion that the negative correlation could have occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure 1.5 has a negative slope (-0.000000435), the linear regression is not statistically significant, and on average, the Western Interconnection frequency response has been stable from 2009 through 2013.

For the Western Interconnection, the data for the years 2009 through 2010 are not very reliable. The value of B was calculated within the first 10 seconds in 2009 and 2010. The other reason the frequency response is much higher for these years is because the capacity of the unit—rather than the net MW loss to the interconnection—was reported. In recent years, such as from 2011 through 2013, better tools have been put in place to detect frequency events and their underlying causes. There are also more systematic procedures to document and verify these events.

Interconnection Frequency Response: Year-to-Year Changes

Eastern Interconnection

The time trend analysis uses the Eastern Interconnection frequency response datasets from 2009 through 2013. The sample statistics by year are listed in Table B.1. The last column lists the number of frequency response events that fell below the absolute IFRO.[111]

Table B.1: Sample Statistics for Eastern Interconnection

Year	Number of Values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum	Number of Events with FR below the IFRO=1014
2009-2013	**257**	**2308.3**	**603.0**	**698.7**	**4335.9**	**3**
2009	44	2258.4	522.5	1404.8	3625.0	0
2010	49	2335.7	697.6	1102.5	4335.9	0
2011	65	2467.8	593.7	1210.0	3815.2	0
2012	28	2314.3	523.6	1374.0	3921.4	0
2013	71	2171.9	596.5	698.7	3696.3	3

Next, Fisher's Least Significant Difference test is used to analyze all pair-wise changes in frequency response. These tests result in the conclusion that there was a statistically significant decrease of frequency response in 2013 compared with 2011, and there were no other statistically significant changes in the expected frequency response by year for the Eastern Interconnection.

[111] http://www.nerc.com/FilingsOrders/us/NERC Filings to FER DL/FR Annual Report 12-27-13 Final.pdf

ERCOT Interconnection

The time trend analysis uses the ERCOT Interconnection frequency response datasets from 2009 through 2013. The sample statistics by year are listed in Table B.2. The last column lists the number of frequency response events that fell below the absolute IFRO.

Table B.2: Sample Statistics for ERCOT Interconnection

Year	Number of Values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum	Number of events with FR below the IFRO=413
2009-2013	**298**	**612.2**	**240.8**	**228.0**	**2552.8**	**34**
2009	51	595.2	185.0	263.5	1299.1	5
2010	67	609.7	164.8	367.6	1152.5	3
2011	65	509.6	131.3	228.0	993.0	15
2012	63	571.2	191.9	290.4	1417.9	9
2013	52	809.8	383.2	378.7	2552.8	2

Next, Fisher's Least Significant Difference test is applied to analyze all pair-wise changes in frequency response. These tests find four statistically significant improvements in the expected frequency response (between 2009 and 2013, between 2010 and 2013, between 2011 and 2013, and between 2012 and 2013).

Several factors contributed to the frequency response performance in the ERCOT Interconnection during the years in which the frequency response did not meet the recommended IFRO (2011 and 2012).

- ERCOT has a small hydro fleet that suffered significantly due to the extreme drought of 2011. There was some relief in 2012, but not in the geographical area of these hydro facilities. Additionally, the owners of the facilities have changed the facilities' operation. Prior to the ERCOT nodal market implementation in December 2010, many of these facilities were operated as frequency responsive reserves. They were on-line in synchronous condenser mode and ramped to full output in about 20 seconds anytime frequency dropped to 59.900 Hz or below, providing 50 to 240 MW of primary frequency response (during the first 20 seconds of a disturbance). Since early 2011, this service has been discontinued.
- There was a drop in natural gas prices and a change in dispatch. The price change caused many of the large coal generators to shut down, and frequency response from these generators had been excellent. The combined-cycle facilities that replaced these units had difficulty getting frequency response to work consistently and correctly. Since the fall of 2012, frequency response from combined-cycle facilities has improved, due to TRE's efforts to work with these generators to improve their performance.
- Another contributing factor was the continued increase in wind generation in ERCOT that typically operates at maximum output. Without margin in the up direction, the interconnection only benefits by curtailing wind generators during high-frequency excursions from these generators. When low-frequency excursions occur, the wind generators cannot provide additional output to increase interconnection frequency.

Québec Interconnection

The time trend analysis uses the Québec Interconnection frequency response datasets for the years 2011 through 2013. The sample statistics by year are listed in Table B.3. The last column lists the number of frequency response events that fell below the absolute IFRO.**Error! Bookmark not defined.**

Table B.3: Sample Statistics for Québec Interconnection						
Year	Number of Values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum	Number of Events with FR below the IFRO=180
2011–2013	**85**	**575.3**	**202.9**	**214.7**	**1228.0**	**0**
2011	20	499.1	153.6	214.7	829.9	0
2012	28	592.7	212.4	305.9	1202.1	0
2013	37	603.3	213.3	250.9	1227.8	0

Next, Fisher's Least Significant Difference test is applied to analyze all pair-wise changes in frequency response. These tests result in the conclusion that there are no statistically significant changes in the expected frequency response by year for Québec Interconnection.

Western Interconnection

The time trend analysis uses the Western Interconnection frequency response datasets for 2009–2013. The sample statistics are listed by year in Table B.4. The last column lists the number of frequency response events that fell below the absolute IFRO.**Error! Bookmark not defined.**

Table B.4: Sample Statistics for Western Interconnection						
Year	Number of Values	Mean of Frequency Response	Std. Dev. of Frequency Response	Minimum	Maximum	Number of Events with FR below the IFRO=949
2009–2013	**119**	**1514.0**	**422.9**	**816.7**	**3125.0**	**3**
2009	25	1513.6	295.7	1000.0	2027.0	0
2010	29	1572.2	512.3	816.7	3125.0	2
2011	25	1496.5	391.9	1078.6	2894.6	0
2012	12	1466.8	557.2	997.0	3123.5	0
2013	28	1491.2	404.3	821.9	2851.0	1

It is impossible to statistically analyze pair-wise annual changes in the Western Interconnection frequency response due to small sample sizes for each year.

Explanatory Variables for Frequency Response and Multiple Regression

Explanatory Variables

In the *2012 State of Reliability* report, Key Finding #2 proposed further work to see if specific indicators could be tied to severity of frequency deviation events. For each interconnection, the following set of six variables is included as explanatory variables (regressors) in the multiple regression models that describe the interconnection frequency response. These variables are not pair-wise uncorrelated, and some pairs are strongly correlated; however, all are included as candidates to avoid the loss of an important contributor to the frequency response variability. Model selection methods help ensure the removal of highly correlated regressors and run multicollinearity diagnostics (variance inflation diagnostic) for a multiple regression model selected.

Summer (Indicator Function) – Defined as 1 for frequency response events that occur from June through August and 0 otherwise.

Winter (Indicator Function) – Defined as 1 for frequency response events that occur from December through February and 0 otherwise.

High Pre-Disturbance Frequency (Indicator Function) – Defined as 1 for frequency response events with pre-disturbance frequency (point A)>60 Hz and 0 otherwise.

On-peak Hours (Indicator Function) – Defined as 1 for frequency response events that occurred during on-peak hours and 0 otherwise. On-peak hours are designated as follows: Monday to Saturday from 0700 to 2200 (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Time – A moment in time (year, month, day, hour, minute, second) when a frequency response event happened. Time is measured in seconds elapsed between midnight of January 1, 1960 (the time origin for the date format in SAS), and the time of a corresponding frequency response event. This is used to determine trends over the study period.

Interconnection Load Level – Measured in megawatts. For the Eastern Interconnection, the data are unavailable for the 2013 events; thus, the multivariate statistical analysis for them involves 2009–2012 data only (186 observations for the Eastern Interconnection). For the ERCOT and Western Interconnections, the analysis covers the five-year data, and for the Québec Interconnection, the 2011–2013 data.

Table B.5 lists the ranks of statistically significant variables of interconnection frequency response for each interconnection. "Positive" indicates positive correlation, "negative" indicates negative correlation, and a dash indicates no statistically significant linear relation. If the initial pre-disturbance frequency is higher than 60 Hz, it is more likely that governor actions will be delayed because of the time it takes for the frequency to drop to the upper dead-band setting.

Table B.5: Observation Summary

Explanatory Valuable	Western	Eastern	ERCOT	Québec
Summer	-	-	-	-
Winter	-	-	-	2 (positive)
High Pre-disturbance	1 (negative)	2 (negative)	1 (negative)	-
On-peak hours	-	-	-	3 (positive)
Time	-	-	2 (positive)	-
Load Level	-	1 (positive)	-	1 (positive)

Eastern Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the Eastern Interconnection frequency response are listed in Table B.6.

Table B.6: Descriptive Statistics

Variable	N	Mean	Std Dev	Minimum	Maximum
Time	186	-	-	1/1/2009	12/31/2012
Interconnection Load	186	343,170	63,792	217,666	541,565
On-Peak Hours	186	0.640	0.481	0	1
A>60	186	0.505	0.501	0	1
Winter	186	0.161	0.369	0	1
Summer	186	0	0	0	1
FR	186	2360	599	1103	4336

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Eastern Interconnection frequency response shown in Table B.7. The value of a coefficient of determination R^2 indicates the percentage in variability of frequency response that can be explained by variability of the corresponding explanatory variable. Out of the six parameters, interconnection load has the biggest impact on frequency response, followed by the indicator of high pre-disturbance frequency. Interconnection load is positively correlated with frequency response (they increase or decrease together, on average), while high pre-disturbance frequency is negatively correlated with frequency response. The events with A>60 Hz have smaller frequency response than the events with A≤60 Hz. The other four variables do not have a statistically significant[112] linear relationship with frequency response.

Table B.7: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant (Yes/No)	Coefficient of Determination of Single Regression (If SS)
Interconnection Load	0.38	Yes	14.4%
A>60	-0.24	Yes	6.0%
On-Peak hours	0.11	No	N/A
Time	0.10	No	N/A
Winter	-0.09	No	N/A
Summer	0.06	No	N/A

Both step-wise selection and backward elimination algorithms[113] result in a multiple regression model that connects the Eastern Interconnection frequency response with the following significant[114] regressors: interconnection load and high pre-disturbance frequency (the other four variables are not selected or were eliminated). The models' coefficients are listed in Table B.8.

Table B.8: Coefficients of Multiple Model

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	1272.19	218.21	5.83	<.0001	0
Interconnection Load	1	0.0036	0.00	5.86	<.0001	1.00067
A>60	1	-304.10	78.60	-3.87	0.0002	1.00067

The adjusted coefficient of multiple determination of the model is 20.0 percent; the model is statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 536 MW/.1 Hz. Variance inflation factors for the regressors do not exceed 1.0007, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. Frequency responses in the Eastern Interconnection are higher due to the large number of disturbances in the dataset in which frequency changes were greater than the generator dead-bands. Also, in earlier studies, the gross output of the unit trip was reported, rather than the net generation[115] megawatt loss to the interconnection.

[112] At significance level 0.1

[113] For step-wise regression algorithm and Backward Elimination algorithm see D. C. Montgomery and G. C. Runger. Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 499-501.

[114] Regressors in the final model have p-values not exceeding 0.1.

[115] There could be a coincident loss of load also.

ERCOT: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the ERCOT Interconnection frequency response are listed in Table B.9.

Table B.9: Descriptive Statistics					
Variable	**N**	**Mean**	**Std Dev**	**Minimum**	**Maximum**
Winter	298	0.305	0.461	0	1
Summer	298	0.252	0.435	0	1
Date	298	-	-	1/1/2009	12/31/2013
A>60	298	0.440	0.497	0	1
On-Peak Hours	298	0.609	0.489	0	1
Interconnection Load	298	38,791	9,745	22,243	64,744
FR	298	612.16	240.75	228.04	2552.75

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the ERCOT Interconnection frequency response shown in Table B.10.

Table B.10: Correlation and Regression Analysis			
Explanatory Variable	**Correlation with FR**	**Statistically Significant (Yes/No)**	**Coefficient of Determination of Single Regression (If SS)**
A>60	-0.31	Yes	9.4%
Time	0.23	Yes	5.3%
Winter	0.07	No	N/A
On-Peak Hours	0.07	No	N/A
Summer	0.04	No	N/A
Interconnection Load	0.02	No	N/A

Out of the six parameters, the indicator of high pre-disturbance frequency has the biggest impact on frequency response, followed by time. High pre-disturbance frequency is negatively correlated with frequency response (the events with A>60 Hz have smaller frequency response than the events with A≤60 Hz, and time is positively correlated with frequency response (on average, frequency response increases with time). The other four variables do not have a statistically significant[116] linear relationship with frequency response.

Finally, both step-wise selection algorithm and backward elimination algorithm result in a multiple regression model that connects the ERCOT Interconnection frequency response with high pre-disturbance frequency and time (the other four variables are not selected or were eliminated[117]) as regressors. The coefficients of the multiple models are listed in Table B.11.

Table B.11: Coefficients of Multiple Model						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t-value**	**p-value**	**Variance Inflation Value**
Intercept	1	-1377.45	484.53	-2.84	0.0048	0
Time	1	0.00000126	0.00000030	4.24	<.0001	1.00002
A>60	1	-147.89	26.15	-5.66	<.0001	1.00002

The adjusted coefficient of multiple determination of the model is 14.0 percent; the model is statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 224 MW/.1 Hz. Variance

[116] At significance level 0.1

[117] Regressors in the final model have p-values not exceeding 0.1.

inflation factors for the regressors do not exceed 1.00002, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model.

Québec: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the Québec Interconnection frequency response are in Table B.12.

Table B.12: Descriptive Statistics					
Variable	**N**	**Mean**	**Std Dev**	**Minimum**	**Maximum**
Winter	85	0.188	0.393	0	1
Summer	85	0.541	0.501	0	1
A>60	85	0.471	0.502	0	1
Time	85	-	-	1/1/2011	12/31/2013
On-Peak Hours	85	0.647	0.481	0	1
Interconnection Load	85	21,635	4,593	14,330	35,140
FR	85	575.30	202.88	214.74	1228

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Québec Interconnection frequency response shown in Table B.13.

Table B.13: Correlation and Regression Analysis			
Explanatory Variable	**Correlation with FR**	**Statistically Significant (Yes/No)**	**Coefficient of Determination of Single Regression (If SS)**
Interconnection Load	0.28	Yes	7.6%
Winter	0.26	Yes	6.7%
On peak Hours	0.18	Yes	3.3%
Time	0.13	No	N/A
Summer	-0.10	No	N/A
A>60	-0.08	No	N/A

Out of the six parameters, interconnection load has the biggest impact on frequency response, followed by the indicators of winter and on-peak hours. Interconnection load, winter, and on-peak hours are positively and statistically significantly[118] correlated with frequency response (the winter events have higher frequency response than other events; the on-peak hour events have higher frequency response than the off-peak hour events; and, finally, the events with higher interconnection load have larger frequency response). The other three variables do not have a statistically significant linear relationship with frequency response.

Finally, both step-wise selection algorithm and backward elimination algorithm result in a single regression model that connects the Québec Interconnection frequency response with interconnection load (the other five variables are not selected or were eliminated[119]). The coefficients of the single model are in Table B.14.

Table B.14: Coefficients of Single Model						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t-value**	**p-value**	**Variance Inflation Value**
Intercept	1	312.1	103.06	3.03	0.0033	0.00
Interconnection Load	1	0.0122	0.00466	2.61	0.0107	1.00

[118] At significance level 0.1

[119] Regressors in the final model have p-values not exceeding 0.1.

The model's adjusted coefficient of determination is 6.5 percent; the model is statistically significant (p=0.01). The random error has a zero mean and the sample deviation σ of 196 MW/.1 Hz. Since the multiple models for the Québec Interconnection frequency response are reduced to a single model, no multicollinearity diagnostics are needed.

The main reason that winter events have a better frequency response is because winter is the peak usage season in the Québec Interconnection. More generator units are on-line; therefore, there is more inertia in the system, so it is more robust in responding to frequency changes in the winter.

Western Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the Western Interconnection frequency response are listed in Table B.15.

Table B.15: Descriptive Statistics

Variable	N	Mean	Std Dev	Minimum	Maximum
Winter	119	0.218	0.415	0	1
Summer	119	0.378	0.487	0	1
Time	119	-	-	1/1/2009	12/31/2013
A>60	119	0.395	0.491	0	1
Interconnection Load	119	92553	17424	60188	143637
On-Peak Hours	119	0.597	0.493	0	1
FR	119	1514	422.9	816.7	3125.0

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Western Interconnection frequency response shown in Table B.16.

Table B.16: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant (Yes/No)	Coefficient of Determination of Single Regression (If SS)
A>60	-0.312	Yes	9.7%
Winter	-0.099	No	N/A
Interconnection Load	0.089	No	N/A
Summer	0.084	No	N/A
Time	-0.048	No	N/A
On-Peak Hours	0.024	No	N/A

Out of the six parameters, the indicator of high pre-disturbance frequency has the biggest impact on frequency response. The indicator is negatively and statistically significantly correlated with frequency response (the events with pre-disturbance frequency greater than 60 Hz have smaller frequency response on average). The other five variables are not statistically significantly[120] correlated with frequency response.

[120] At significance level 0.1

Finally, both step-wise selection algorithm and backward elimination algorithm result in a single regression model that connects the Western Interconnection frequency response with one regressor, the indicator of high pre-disturbance frequency (the other five variables are not selected or were eliminated[121]). The coefficients of the single model are listed in Table B.17.

Table B.17: Coefficients of Single Model						
Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	1620.4	47.56	34.07	<.0001	0.00
A>60	1	-268.7	75.68	-3.55	0.0006	1.00

[121] Regressors in the final model have p-values not exceeding 0.1.

Appendix C – Statistical Summary of SRI$_{bps}$ Assessment

The PAS has investigated the SRI$_{bps}$ performance for 2008–2013 as well as a year-by-year comparison. From this analysis it concluded that 2011 performance was the best SRI$_{bps}$ on record, as measured by its mean and standard deviation, in spite of the relatively large standard deviation (whose outliers included the September 8, 2011 load shed event, in addition to the February 2, 2011 cold weather load loss event). It also determined that 2009 and 2013 were the next best performance years, followed by 2010, 2012, and 2008. These values are shown in Table C.1 below.

Table C.1: Descriptive Statistics of Annual SRI $_{bps}$

Year	N	SRI $_{bps}$ Mean	SRI $_{bps}$ Std Dev
2008	366	1.801	0.674
2009	365	1.664	0.528
2010	365	1.742	0.611
2011	365	1.504	1.041
2012	366	1.785	0.813
2013	365	1.670	0.600

This ranking is further visible in Figure C.1 below. It can be observed that if outlier performance were taken as a larger input to ranking the year's results, 2011 and 2012 would be considered poorer performance years, while 2013 and 2009 would be rated as the best performance years.

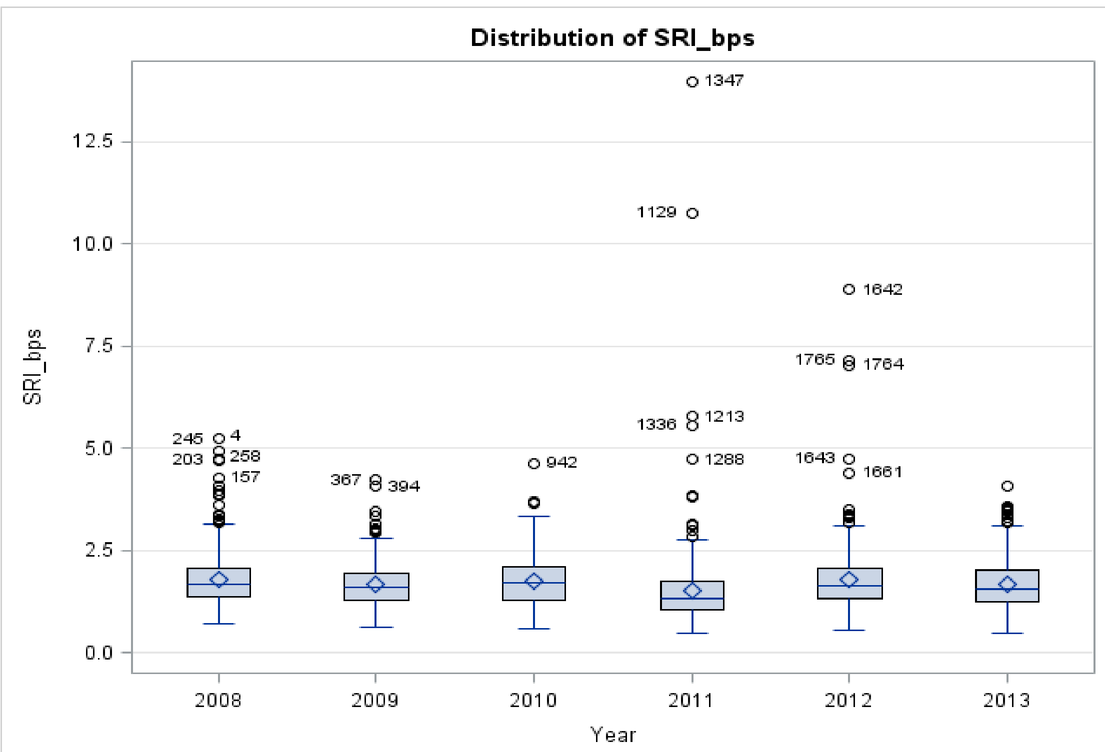

Figure C.1: Boxplot of Annual SRI$_{bps}$

Finally, the performance of each year compared to every other year is depicted in Table C.2 below; if no reference to statistical significance is made within the table, it is assumed to be statistically significant.[122]

Table C.2: Pair-wise Comparison of Annual SRI $_{bps}$

	Compared to Year					
Base Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
2008		2009 Better	2010 Better, but not Statistically Significant	2011 Better	2012 Better, but not Statistically Significant	2013 Better
2009			2009 Better, but not Statistically Significant	2011 Better	2009 Better	Approximately Equal
2010				2011 Better	2012 Better, but not Statistically Significant	2013 Better, but not Statistically Significant
2011					2011 Better	2011 Better
2012						2013 Better
2013						

The second analysis performed was an assessment of the distribution. Performance is most closely represented as a log-normal distribution; however, 2011 and 2012 do not fit that distribution.

Table C.3: SRI $_{bps}$ Parameters for Fitted Log-normal Distribution

Parameter	Symbol	2008 Estimate	2009 Estimate	2010 Estimate	2011 Estimate	2012 Estimate	2013 Estimate	2008–2013 Estimate
Minimum p-value*	P	**0.205**	**>0.50**	**0.082**	**0.009**	**0.007**	**>0.250**	**0.001**
Fit to Log-normal		Good	Very good	Poor	Not fitted	Not fitted	Good	Not fitted
Threshold	Theta	0.389	0.059	-0.196			-0.491	
Scale	Zeta	0.247	0.422	0.613			0.734	
Shape	Sigma	0.440	0.319	0.312			0.273	
Mean		**1.799**	**1.664**	**1.743**			**1.670**	
Std Dev		**0.651**	**0.525**	**0.620**			**0.601**	

[122] At significance level 0.05.

In Figure C.2 below is the histogram for 2013 SRI_{bps}, which did conform to a log-normal distribution.

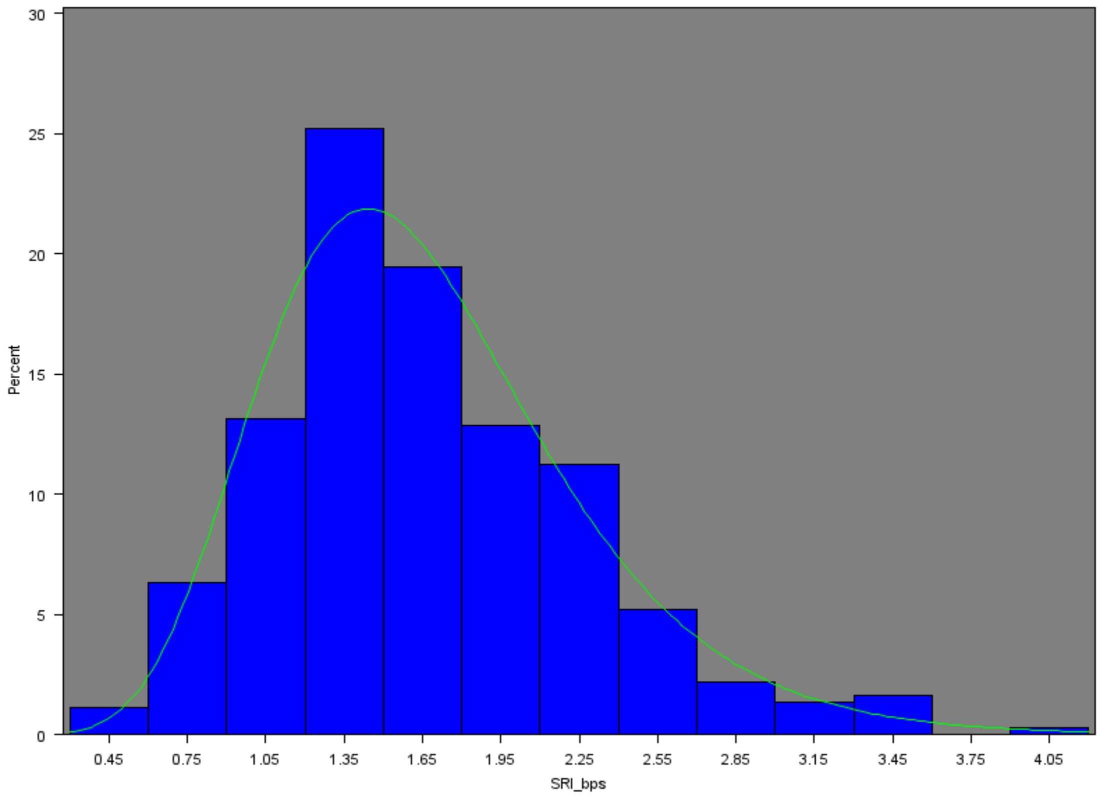

Figure C.2: Histogram for SRI_{bps} for 2013

In Figure C.3 below, the trend of performance is shown over the six-year history. It is notable that the trend of performance over this period is improving, which is very close to statistically significant;[123] statistical significance means that the changes observed are real changes and are not due to random variations in the data.

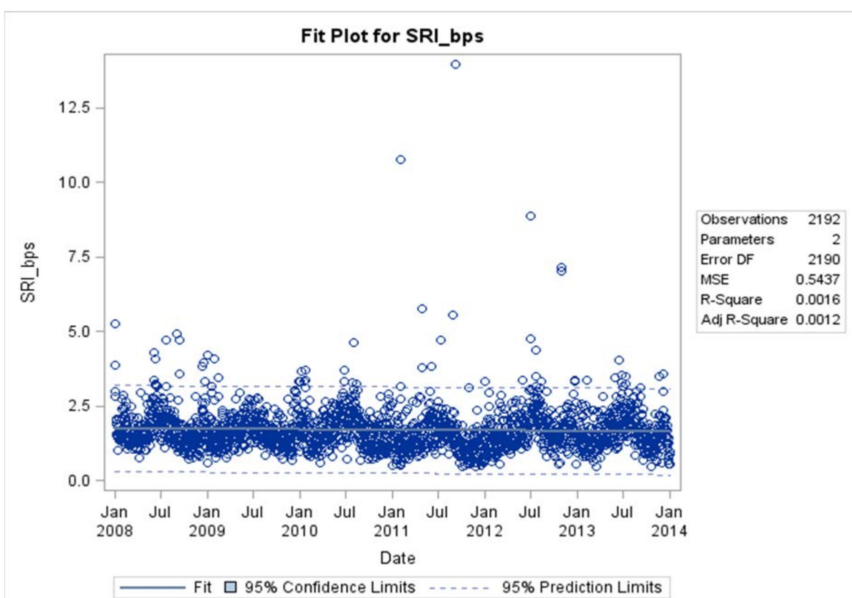

Figure C.3: Fit Plot for SRI_{bps} 2008–2013

[123] Significance of the linear regression describing the time trend is P=0.06.

Appendix D – Abbreviations Used in This Report

Acronym	Description
ALR	Adequate Level of Reliability
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Common/Dependent Mode
EEA	Energy Emergency Alert
ERO	Electric Reliability Organization
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
ICC	Initiating Cause Code
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	ISO New England
KCMI	Key Compliance Monitoring Index
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent Service Operator
PAS	Performance Analysis Subcommittee
PSMTF	Protection System Misoperation Task Force
RC	Reliability Coordinator
RE	Regional Entities
RF	ReliabilityFirst
RSG	Reserve-Sharing Group
SERC	SERC Reliability Corporation
SNL	Sandia National Laboratories
SOL	System Operating Limit
SPS	Special Protection Schemes
SPCS	System Protection and Control Subcommittee
SPP	Southwest Power Pool
SRI	Severity Risk Index
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TO	Transmission Owner
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Contributions

Acknowledgements

NERC would like to express its appreciation to the many people who provided technical support and identified areas for improvement.

NERC Industry Groups

Table 1 lists the NERC industry group contributors.

Table 1: NERC Group Acknowledgements

Group	Officers
Planning Committee Reviewers	John Feit, Public Service Commission of Wisconsin David Jacobsen, Manitoba Hydro Dale Burmester, American Transmission Company, LLC
Performance Analysis Subcommittee	Chair: Melinda Montgomery, Entergy Vice Chair: Heide Caswell, PacifiCorp
Demand Response Availability Data System Working Group	Chair: Bob Collins, TRE Vice Chair: Mike Jaeger, ISO-NE
Events Analysis Subcommittee	Chair: Sam Holeman, Duke Energy Vice Chair: Hassan Hamdar, FRCC
Generation Availability Data System Working Group	Chair: Gary Brinkworth, TVA Vice Chair: Leeth DePriest, Southern Company
Transmission Availability Data System Working Group	Chair: Jake Langthorn, Oklahoma Gas and Electric Co. Vice Chair: Jeff Schaller, Hydro One Networks, Inc.
Resources Subcommittee	Chair: Don Badley, Northwest Power Pool Corp. Vice Chair: Gerald Beckerle, Ameren Services
Operating Reliability Subcommittee	Chair: Joel Wise, TVA Vice Chair: Eric Senkowicz, FRCC
Frequency Working Group	Chair: Sydney Niemeyer, NRG Energy
Operating Committee	Chair: Tom Bowe, PJM Interconnection, LLC Vice Chair: James D. Castle, Duke Energy
Planning Committee	Chair: Ben Crisp, SERC Reliability Corporation Vice Chair: Ben Crisp, SERC Reliability Corporation
Reliability Assessment Subcommittee	Chair: Vince Ordax, FRCC Vice Chair: Layne Brown, WECC
System Protection and Control Subcommittee	Chair: William J. Miller, Exelon Corporation Vice Chair: Philip B. Winston, Southern Company
Protection System Misoperations Task Force	Chair: John Seidel, Midwest Reliability Organization
Spare Equipment Database Working Group	Chair: Dale Burmester, American Transmission Company, LLC Vice Chair: Puesh Kumar, APPA
Compliance and Certification Committee	Chair: Terry Bilke, Midwest ISO, Inc. Vice Chair: Patricia E. Metro, National Rural Electric Cooperative Association

Regional Entity Staff

Table 2 provides a list of the Regional Entity staff that provided data and content review.

Table 2: Contributing Regional Entity Staff	
Name	**Regional Entity**
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John Seidel	MRO
Phil Fedora	NPCC
Paul Kure	RF
John Johnson	SERC
Alan Wahlstrom and Deborah Currie	SPP
Bob Collins	TRE
Matthew Elkins	WECC

NERC Staff

Table 3 provides a list of the NERC staff who contributed to this report.

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